C11
3:C65
no.5
c.2

North Carolina State Library
Raleigh

N.C.
Doc

Outer Continental Shelf Development and the North Carolina Coast: A Guide for Local Planners

JUN 28 1983

David J. Brower
Center for Urban and Regional Studies
University of North Carolina, Chapel Hill

William D. McElyea
Center for Urban and Regional Studies
University of North Carolina, Chapel Hill

David R. Godschalk
Department of City and Regional Planning
University of North Carolina, Chapel Hill

Nancy D. Lofaro
Center for Urban and Regional Studies
University of North Carolina, Chapel Hill

North Carolina
Coastal Energy Impact Program
Office of Coastal Management
North Carolina Department of Natural Resources
and Community Development

NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION
U.S. DEPARTMENT OF COMMERCE

CEIP REPORT NO. 5
AUGUST 1981

To order:

Residents of North Carolina may receive a single copy of a publication free upon request. Non-residents may purchase publications for the prices listed. Because of the production costs involved, some of the publications carry a minimal charge regardless of residency. Prices for these are indicated in the price list as being "for all requests".

When ordering publications please provide the publication number and title and enclose a check made payable to DNRCD. For a complete list of CEIP publications - or to place an order - contact:

Coastal Energy Impact Program
Office of Coastal Management
N.C. Department of Natural
  Resources and Community
  Development
Box 27687
Raleigh, NC 27611

Series Edited by James F. Smith
Cover Design by Jill Miller

Outer Continental Shelf Development and the North Carolina Coast: A Guide for Local Planners

BY

David J. Brower
Center for Urban and Regional Studies*

William D. McElyea
Center for Urban and Regional Studies*

David R. Godschalk
Department of City and Regional Planning*

Nancy D. Lofaro
Center for Urban and Regional Studies*

The preparation of this report was financed through a Coastal Energy Impact Program grant provided by the North Carolina Coastal Management Program, through funds provided by the Coastal Zone Management Act of 1972, as amended, which is administered by the Office of Coastal Zone Management, National Oceanic and Atmospheric Administration. This CEIP grant was part of NOAA grant NA-80-AA-D-CZ147.

Project No. CEIP-80-03

Contract No. C-6040

August 1981

*University of North Carolina
at Chapel Hill
Chapel Hill, North Carolina 27514

Table of Contents

Acknowledgements v

Abstract vii

List of Figures ix

List of Tables xi

Summary and Conclusions xii

Recommendations xvi

Chapter One: Introduction 1

  Planning and OCS Development Issues 1

  Key Points of Interest in OCS Development 2

Chapter Two: Preparing for OCS-Related Development 8

  Understanding OCS Operations and Regulatory Processes 9
    Background Readings
    Keeping Up-to-Date

  Establishing and/or Reviewing Community Objectives 12
    Land Use
    Environmental Quality
    Local Economy

Chapter Three: The Stages of OCS Development 16

  The Leasing Stage 19
    Pre-Lease Exploration and its Onshore Impacts
    The Leasing Process
      Local and Regional Participation in Lease Sale Procedures

  The Exploration Stage 28
    Exploration Activities and their Onshore Impacts
      Exploratory Drilling 30
        Impacts on the Local Economy
        Impacts on Natural Resources
      Temporary Service Bases 35
        Impacts on the Local Economy
        Impacts on Natural Resources

Marine Repair and Maintenance Yards 42
Impacts on the Local Economy
Impacts on Natural Resources
General Shore Support or Ancillary Services 45
Impacts on the Local Economy
Impacts on Natural Resources
Federal Activities and the Flow of Information 50

The Field Development Stage 63
Field Development Activities and their Onshore Impacts
Development Drilling 65
Impacts on the Local Economy
Impacts on Natural Resources
Permanent Service Bases 72
Impacts on the Local Economy
Impacts on Natural Resources
Platform Fabrication Yards 77
Impacts on the Local Economy
Impacts on Natural Resources
Pipelines 85
Impacts on the Local Economy
Impacts on Natural Resources
Pipe Coating Yards 101
Impacts on the Local Economy
Impacts on Natural Resources
Platform and Platform Installation Support Bases . . . 106
Impacts on the Local Economy
Impacts on Natural Resources
Partial Processing Facilities 108
Impacts on the Local Economy
Impacts on Natural Resources
Gas Processing and Treatment Plants 115
Impacts on the Local Economy
Impacts on Natural Resources
Marine Oil Terminals 122
Impacts on the Local Economy
Impacts on Natural Resources
Refineries 133
Impacts on the Local Economy
Impacts on Natural Resources
Federal Activities and the Flow of Information during Field Development 145

The Production Stage 160

The Shutdown Stage 164

Chapter Four: Options for Local Planners 166

Coastal Area Management Act 166

Local Options 168
Understanding the OCS Development Process
Establishing Communications
Evaluating Community Capacity
Setting Up Policies and Programs

Land Use and Development Management Ordinances 172

Leasing 175

Summary 176

References 177

Appendix A: Annotated Bibliography 178

Overviews, Methodologies, and Handbooks 179

Case Studies 196

Regional Information 208

Appendix B: Sample Ordinances, Resolutions, and Policies 217

Santa Barbara County, California 218

City of New Bedford, Massachusetts 221

Northampton County, Virginia 224

Troy, Michigan 234

Appendix C: North Carolina Environmental Permits 238

Appendix D: Directory of OCS-Related State and Federal Agencies . . . 251

Acknowledgements

This study could not have been accomplished without the assistance of many people. We are grateful to all those who helped with the work and the ideas.

The authors especially wish to acknowledge the major contribution of Julie Shambaugh, a research assistant in the Center for Urban and Regional Studies and a graduate student in the Department of City and Regional Planning, who designed and produced the report graphics. Her drawings not only help to describe the various facilities and equipment used in outer continental shelf development but also enhance the attractiveness of a rather technical publication.

We very much appreciate the accurate and precise work of Lee Mullis, who typed the report drafts and final copy with exceptional speed and care.

Some of the early work on the project was done by Georgiana Blomberg, who was a research assistant in the Center for Urban and Regional Studies during the fall of 1980.

We owe a special debt to Jim Smith, the North Carolina Coastal Energy Impact Coordinator, who provided both support and guidance to this project.

The report was reviewed at a meeting in Wilmington in June 1981, by a number of government officials concerned with North Carolina coastal development. We acknowledge the useful and practical suggestions made by:

- Bill Farris, Assistant City Manager for Planning and Development, City of Wilmington
- Glenn Harbeck, Planner, City of Wilmington
- Arcelia Wicker, Sr., Community Development Administrator, City of Wilmington
- Karen Gottovi, Coastal Resources Commission member and County Commissioner, New Hanover County
- Dexter Hayes, Director, Office of Planning, New Hanover County
- Jack Munn, Planner, New Hanover County
- John Harvey, Planning Director, Brunswick County
- Donald T. Davis, Administrator, Morehead City

- Cecil W. Sewell, Building Inspector, Morehead City
- Jim Smith, Office of Coastal Management, Raleigh
- Ralph Cantral, Office of Coastal Management, Raleigh
- Gaile Pittman, Office of Coastal Management, Raleigh
- John Crew, Office of Coastal Management, Washington, N.C.

Finally, we thank all those who published case studies and planning methodologies from other localities impacted by outer continental shelf development. Without their earlier efforts, our work would have been many times more difficult.

Abstract

Outer Continental Shelf Development
and the
North Carolina Coast:
A Guide for Local Planners

This guide supplies local governments in North Carolina's coastal region with information on (1) the facilities and activities associated with outer continental shelf (OCS) oil and gas development, (2) their impacts on coastal communities, and (3) how local governments can manage these impacts. The negative impacts of OCS development can be reduced and its positive impacts enhanced by understanding the offshore development process, anticipating its effects, and pursuing appropriate actions to handle them. Since the North Carolina coast is a "frontier" region with no experience in offshore oil and gas production, sound planning by local governments is essential to guarantee a long-term net benefit to the local environment, economy, and fiscal capacity.

Concise descriptions are provided of the offshore oil and gas activities and related onshore facilities that accompany each stage of OCS development: leasing, exploration, field development, production, and shutdown. These descriptions include factors influencing the location of facilities, their impact on the local economy, and their impact on local natural resources.

The guide helps local governments apply this information by presenting ways in which they can influence the development process. Major offshore decisions are made by the federal government and the oil industry, with state and local governments having the opportunity to review and comment on offshore development proposals. The guide describes key federal regulatory procedures and opportunities for local participation in controlling offshore development. The bulk of a local government's power stems from its authority to regulate the location and timing of onshore facilities development. The guide identifies planning tools and strategies available to local governments in North Carolina for managing and regulating onshore development.

An annotated bibliography at the end of the guide concisely describes numerous reports addressing the onshore impacts of OCS development. The literature covered in the bibliography ranges from general overviews of OCS

development to case studies which relate the experiences of coastal areas already exposed to offshore and onshore development. Local government officials can use the bibliography to select interesting and relevant literature for more detailed study of OCS development and its onshore effects. Following the bibliography are excerpts from ordinances, resolutions and policies used to manage and regulate onshore activities in other locations, a listing and description of the North Carolina environmental permits for onshore OCS facilities, and a directory of federal and North Carolina state agencies which have roles in regulating offshore and onshore oil and gas development.

List of Figures

1. Areas of the OCS Under Consideration for Leasing by the U.S. Bureau of Land Management 2

2. Leased Tracts (Sale 43) and Proposed Leased Tracts (Sale 56) 4

3. Potential Timing and Inventory of OCS Development off the Coast of North Carolina 6

4. Activity Levels During the Five Stages of OCS Development 16

5. Industry Activities in the OCS Development Process 17

6. Geophysical Surveying Equipment 20

7. Offshore Drilling Crew 31

8. Jack-up Rig 31

9. Semi-submersible Rig 32

10. Drill Ship 32

11. Temporary Service Base 36

12. Crew and Supply Vessels that Operate out of a Temporary Service Base 37

13. Steel Fixed-Pile Platform 66

14. Towing the Steel Jacket to the Drilling Site 66

15. Concrete Gravity Platform 67

16. Towing the Concrete Platform to the Drilling Site 67

17. Recent Developments in Deepwater Production Rigs 68

18. Directional Drilling 69

19. Permanent Service Base 72

20. Platform Fabrication Yard 77

21. Lay Barge Operations 89

22. Reel Barge 90

23. Bottom Pull Method of Pipeline Installation 91

24. Flotation Method of Pipeline Installation 92

25. Pipeline Trenching Equipment 93

26. Pipelaying at the Landfall 94

27. Trench Lined with Sheet Piling at the Landfall 94

28. Pipelaying in Wetlands 95

29. Pipe Coating Yard 102

30. Gas Processing and Treatment Plant 118

31. Shoreside Fixed-Pier Treminal 124

32. Relationship of Single Point Mooring System to Production Platform 126

33. Oil Refinery 133

34. Timing of Production from a Typical Offshore Oil and Gas Field 161

List of Tables

1. Major OCS Support Companies and their Average Employment 48

2. Materials Handled at Service Bases 73

3. Service Base Labor Requirements for Different OCS Stages 76

4. Oil Pipeline Accidents - 1972 100

5. Air Emissions from a Partial Processing Facility with an 80,000 Barrel-Per-Day Capacity 112

6. Allowable Pollutant Concentrations Contained in Processed Formation Water 113

7. Tanker Dimensions and Pumping Rates 126

8. Employment at Selected Marine Terminals and Storage Tank Farms 127

9. Typical Evaporative Emissions from the Transfer of Crude Oil 129

10. Emissions from Coking and Catalytic Cracking Units With and Without Electrostatic Precipitators and CO Boilers 138

11. Emissions from Boilers and Compressors 139

12. Process Water Contaminants 141

Summary and Conclusions

The first sale of outer continental shelf (OCS) leases for oil and gas exploration off the North Carolina coast took place during August 1981, with subsequent sales to take place in later years. Private petroleum companies bid for these offshore leases in sales managed by the Bureau of Land Management of the U.S. Department of Interior. Because the OCS lease sites are located in the Atlantic Ocean beyond the three-mile territorial jurisdiction of the State of North Carolina, the ocean bottom is considered federal land, and the federal government controls the leasing process.

State and local governments, however, play a major role in the various stages of offshore oil and gas production. They not only review and comment on federal OCS actions, but also have primary responsibility for guiding and regulating the major onshore activities related to offshore oil and gas development. While it is not yet known whether the continental shelf off North Carolina will be the location of extensive offshore oil and gas production, it is known that there could be major social, environmental, and economic impacts on North Carolina's coastal communities should such production occur.

PURPOSE AND APPROACH

The purpose of this report is to provide a guide for local planners and decision makers in North Carolina's coastal region with information on (1) the facilities and activities associated with outer continental shelf oil and gas development, (2) their impacts on coastal communities, and (3) how local governments can manage these impacts. The negative impacts of OCS development can be reduced and its positive impacts enhanced by understanding the offshore development process, anticipating its effects, and pursuing appropriate actions to handle them. Since the North Carolina coast is a "frontier" region with no experience in offshore oil and gas production, sound planning by local governments is essential to help ensure long-term net benefits to the local environment, economy, and fiscal capacity from the development of offshore oil and gas resources.

The primary audience for this report consists of local government planners and decision makers in the coastal cities and counties of North Carolina. Other readers interested in the potential impacts of OCS development, including citizens, architects and engineers, developers and bankers, marine business men and women, and environmentalists, may also find it useful. The material in the report is designed to give a clear and comprehensive picture of the facilities used in OCS development, from offshore drilling rigs to marine oil terminals, and the steps that take place in the OCS development process, from initial exploration through full-scale oil and gas production to final shutdown.

Material for this report was selected from the extensive literature that already exists on OCS development. No new methodologies were devised during this project; rather, the approach was (1) to assemble and review the published methodologies and techniques of other localities which have already experienced OCS development impacts and (2) to identify their key points for North Carolina decision makers and planners.

REPORT ORGANIZATION

This guide is organized around the search for information that local government officials would go through in preparing to manage the impacts of offshore oil and gas development on their communities:

> Chapter I -- the Introduction -- highlights key points of interest concerning the overall OCS development process.
>
> Chapter II -- Preparing for OCS-Related Development -- contains suggestions for learning about OCS development, evaluating its relationship to the local community, and establishing policies to guide future local actions regarding its onshore impacts.
>
> Chapter III -- The Stages of OCS Development -- contains concise descriptions of the offshore oil and gas activities and related onshore facilities that accompany each stage of OCS development: leasing, exploration, field development, production, and shutdown. These descriptions include factors influencing the location of facilities, their impact on local employment, and their impact on local natural resources. Following each set of facility descriptions is a discussion of various documents (plans, permits, etc.) generated by the offshore industry and the federal government during each development stage. This discussion includes local opportunities for reviewing the documents and participating in offshore development decisions. Major offshore decisions are made by industry and the federal government; local and state governments have the opportunity to review and comment on offshore development proposals. The bulk of local government's power over OCS development rests in its direct control over the location and timing of onshore facilities.
>
> Chapter IV -- Options for Local Planners -- presents planning tools and strategies available to local governments in North Carolina for controlling and influencing onshore development. This includes direct public powers, such as zoning and site plan review, and local participation in state permit decisions.

Appendix A is an annotated bibliography which describes selected reports addressing OCS development and its onshore impacts. The literature covered in the bibliography ranges from general overviews of OCS development to case studies which relate the experiences of coastal communities already exposed to onshore and offshore oil and gas activities. Local planners can use the bibliography to select interesting and relevant literature for more detailed study of the OCS issue.

Appendix B contains excerpts from ordinances, resolutions, and policy statements that have been formulated by communities elsewhere in the United States (1) to influence the pattern of OCS development or (2) to influence industrial development by using innovative planning techniques.

Appendix C describes various permits issued by North Carolina state agencies which are likely to be required of onshore and nearshore oil and gas activities. Local planners should familiarize themselves with these permits and the local role in permit procedures.

Appendix D is a directory of key federal and North Carolina state agencies which have roles in managing offshore and onshore oil and gas activities.

This guide gives local planners and public officials a comprehensive understanding of the OCS development process and their relationship to it. It also leads them to further, more detailed information by describing different reports and documents and identifying where they can be obtained.

CONCLUSIONS

The outer continental shelf (OCS) development process occurs in five basic stages:

1. Leasing, during which limited pre-lease exploration efforts are conducted by private companies, and then a formal lease sale procedure is carried out by the Bureau of Land Management where petroleum companies obtain rights by competitive bidding to explore and develop offshore tracts.

2. Exploration, during which petroleum companies search the offshore tracts for oil and gas and onshore impacts begin to appear in coastal communities in the form of service bases and related industrial facilities.

3. Field development, during which wells are drilled in the offshore oil and gas fields discovered during exploration and onshore impacts expand to include fabrication yards, pipelines, tanker terminals, processing plants, and refineries.

4. Production, during which oil and gas resources are recovered and brought ashore for processing and sale.

5. Shutdown, during which the depleted oil and gas resources are no longer economically recoverable and offshore wells and pipelines are capped and facilities are removed or converted to other uses.

Local government has the greatest problems and opportunities during the second and third stages of OCS development -- exploration and field development. The leasing stage is dominated by the federal and state governments. Production does not require the construction of new onshore facilities and often brings about a decline in the number of OCS-related jobs since much of the production process is automated. Shutdown brings further job losses, along with decreases in all other OCS activity, and presents a transition problem for local government. During exploration and field development, however, affected local governments may find themselves working at a feverish pace to understand and assess the impacts of OCS development on their jurisdictions and to devise effective plans and management systems to mitigate negative impacts and to capitalize on positive impacts.

Local planning for the impacts of OCS-related development should begin during the leasing stage in preparation for the exploration and field development stages, when heavy construction projects will require development review and permit approval. The field development stage can bring a construction "boom," creating temporary high levels of employment which will taper off significantly once production begins. In small communities, this boom period can be chaotic, as existing housing, public services, environmental, and fiscal capacities are strained to their limits. Monitoring the impacts of onshore facility operations is the prime local government activity during the production stage. Finally, as shutdown approaches, local planners and decision makers must prepare contingency strategies to face the strains of transition away from oil and gas production to other local economic activities.

If economically recoverable reserves of oil or gas exist off the coast of North Carolina, the state's coastal communities will undoubtedly experience OCS-related onshore development. The extent and impacts of this development hinge on a variety of factors: the actual volume of offshore resources, the market prices of oil and gas, the cost of mining them, the location of offshore fields relative to existing support facilities and fuel markets, the availability of appropriate onshore development sites and workers, the tenor of government regulations, and public attitudes toward OCS-related industrial development. At this time, we cannot predict the exact future impacts of OCS development on North Carolina. We can study the impacts and local government responses in areas that have already experienced OCS development to prepare ourselves to manage the impacts should they occur.

Recommendations

In order to effectively cope with the local impacts of outer continental shelf (OCS) oil and gas development, planners and decision makers in North Carolina's coastal communities should begin early in the development process to prepare public policies, plans, regulations, and strategies which will mitigate the impacts of OCS development.

Four basic steps are recommended:

1. Understand the basics of offshore industry operations and their onshore impacts, as well as the federal regulatory process and the information it generates.
2. Establish lines of communication with relevant federal and state agencies, the industry, and local citizens.
3. Evaluate the community's ability and desire to serve the needs of the oil and gas industry.
4. Review and/or establish community policies to guide onshore development.

The first step, understanding what goes on in the OCS development process, can be taken by studying this report and others listed in the bibliography (Appendix A). A careful reading of this guide should provide the basic information necessary.

The second step, establishing communication lines, should focus on key state-level officials. Contact should be made initially with at least the Coordinator of the Coastal Energy Impact Program in the Department of Natural Resources and Community Development and the OCS Coordinator in the Office of Marine Affairs, Department of Administration. Both of these officials are located in Raleigh. Appendix D lists their addresses and telephone numbers.

The third step, evaluating the community's ability and desire to serve the oil and gas industry, involves two types of actions. First, local planners and decision makers should survey relevant local resources, such as harbor facilities, skilled marine workers, repair yards, and terminal sites. Second, local planners and decision makers should conduct a community discussion of the pros and cons of being a host community to the offshore oil and gas industry.

This might take the form of a workshop in which experts are invited to discuss the issues with local citizens, and/or a forum in which local government, business, and civic leaders explore the likely impacts of OCS development on the community. These events might suggest the need to set up a community task force on OCS development which could help formulate related community policies and programs.

The fourth step, setting up community policies and programs to guide onshore development, involves adopting public goals and designing local ordinances and actions to carry out these goals. By creating specific districts in local zoning ordinances, such as harbor industrial districts, a locality can identify the performance standards that it expects for onshore facility construction and operation. At this stage, it could be particularly helpful to draw both on the experience of other communities and on the recommendations of a local task force or working group of government and business leaders.

At a minimum, each local government likely to be affected by OCS development should (1) designate a responsible public official to take the lead role in coordinating the local OCS impact management effort and (2) adopt a local ordinance to regulate onshore construction. The responsible public official may be a planner, a building official, an engineer, or a city or county manager. The ordinance may be a section of a zoning ordinance or a more specialized ordinance. Examples of both basic and more extensive local actions are provided in the report for those communities with the resources to undertake them.

The importance of an active and timely effort to seek out information about the OCS process and its North Carolina impacts cannot be overstressed. The local governments which have taken the trouble to prepare themselves for OCS development are the ones that will be able to capture its opportunities and avoid its pitfalls.

CHAPTER ONE: INTRODUCTION

The United States is presently engaged in an effort to develop the oil and gas resources of the outer continental shelf (OCS). Expansion of the federal oil and gas leasing program by the Department of the Interior to the Atlantic continental shelf has posed a number of new and complex questions for North Carolina and the other coastal states.

Planning and OCS Development Issues

OCS-related facilities and the development which will accompany them will have significant effects on the region and communities where such facilities occur. For example, oil and gas production could create an influx of workers that could significantly change an area's employment patterns and influence tax revenues, water quality, air quality, and the demand for public services.

The need for sound planning to accommodate the onshore impacts of offshore oil and gas development has long been recognized. Many of the impacts can be prevented, reduced, or ameliorated by proper anticipation and action. Much of this planning burden falls on local governments in North Carolina since, under state law, they have the authority and duty to plan for and provide most of the necessary public services (including water, sewer, transportation, schools, and housing). These burdens will be especially acute for the state's urban coastal areas (Wilmington, Morehead City, Beaufort, and Southport), which are the most likely locations for development because these areas have limited capacities to absorb new development. In many of these urban areas, water and sewer facilities are limited, schools are near capacity, and available housing supply is minimal.

Much research and study has been done in several regions of the United States and throughout the world to identify the characteristics and impacts of energy-related development. Methodologies have been devised to help plan for this development and to aid in the mitigation of outer continental shelf (OCS) oil and gas activity. The information contained in this guide, which draws heavily on this research, has been compiled to aid local planners in North Carolina in developing strategies to deal with OCS-related developments. Although aimed primarily at local planners, the guide also has relevance for planners and government officials involved with economic development, transportation, housing, and environmental concerns at both the regional and state levels. With help from this guide and its related bibliographic references, local planners can apply sound planning principles and techniques to any future OCS-related activity that may confront and affect them.

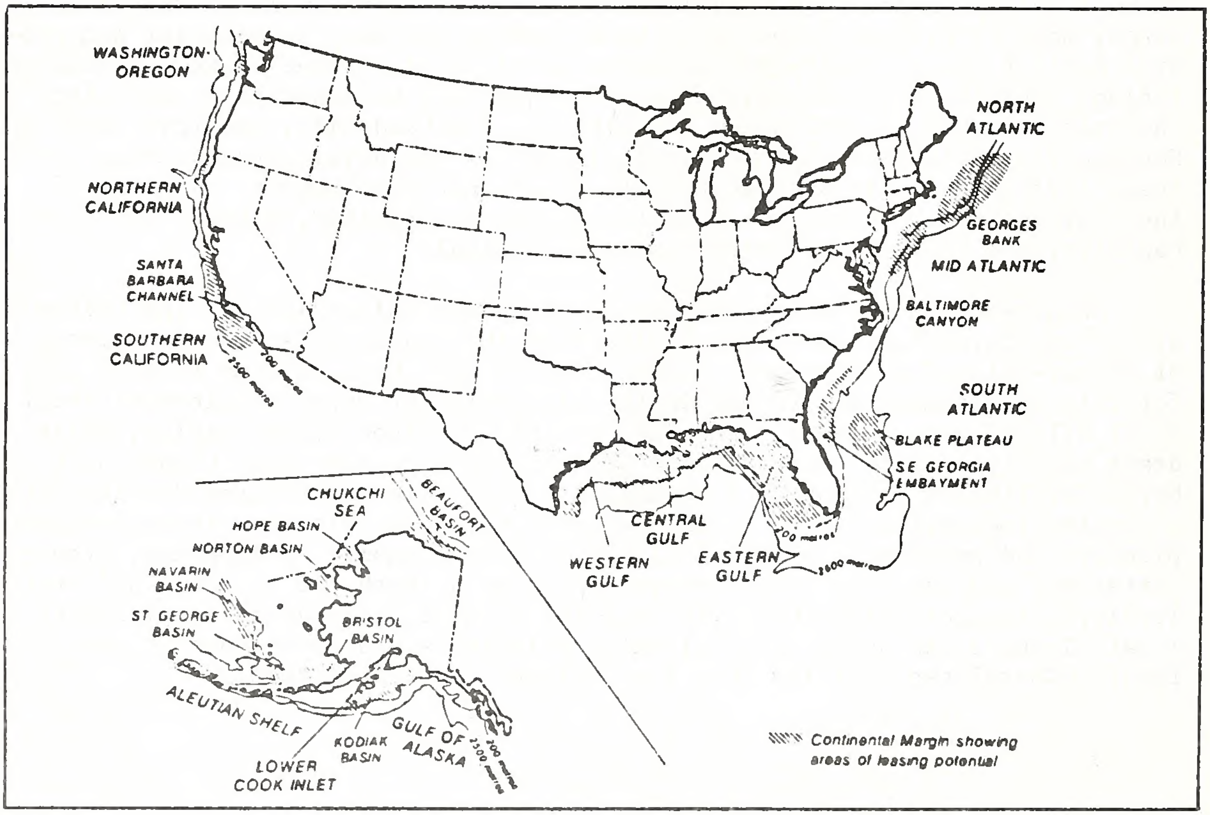
Key Points of Interest in OCS Development

Leasing tracts on the nation's outer continental shelf in order to increase the domestic production of oil and gas is a highly technical and complex process because of the many actors involved. The following points of interest have been adapted from a publication by the American Society of Planning Officials for state and local planners who are responsible for understanding OCS oil and gas development and for managing its related onshore impacts (ASPO, Anticipating and Planning for the Impacts of OCS Oil and Gas Development):

1. Since 1974, the Department of the Interior has operated under an accelerated program of leasing to permit oil and gas exploration of the outer continental shelf.

The outer continental shelf (OCS) is that portion of the ocean floor beyond the states' territorial waters (the three-mile limit; three leagues off Texas and West Florida) and under the jurisdiction of the federal government. General areas of the OCS that the Department of the Interior -- which is responsible under law for overseeing the development of minerals on the OCS -- has leased or is considering for oil and gas leasing are shown in Figure 1.

Figure 1
Areas of the OCS Under Consideration for Leasing



SOURCE: Bureau of Land Management/U.S. Geological Survey. Leasing and Management of Energy Resources on the Outer Continental Shelf, 1976.

In 1974, in an effort to decrease the nation's dependence on foreign petroleum, the Department of the Interior announced an accelerated schedule of offshore leasing. Even though the Department's goal of approximately six OCS lease sales per year from 1977 through 1981 has been behind schedule, sales have long been held in southern California and the Gulf of Mexico, where development is already underway, and in such "frontier" areas as the Gulf of Alaska, the Mid-Atlantic region (the Baltimore Canyon Trough), and the North Atlantic region (the Georges Bank).

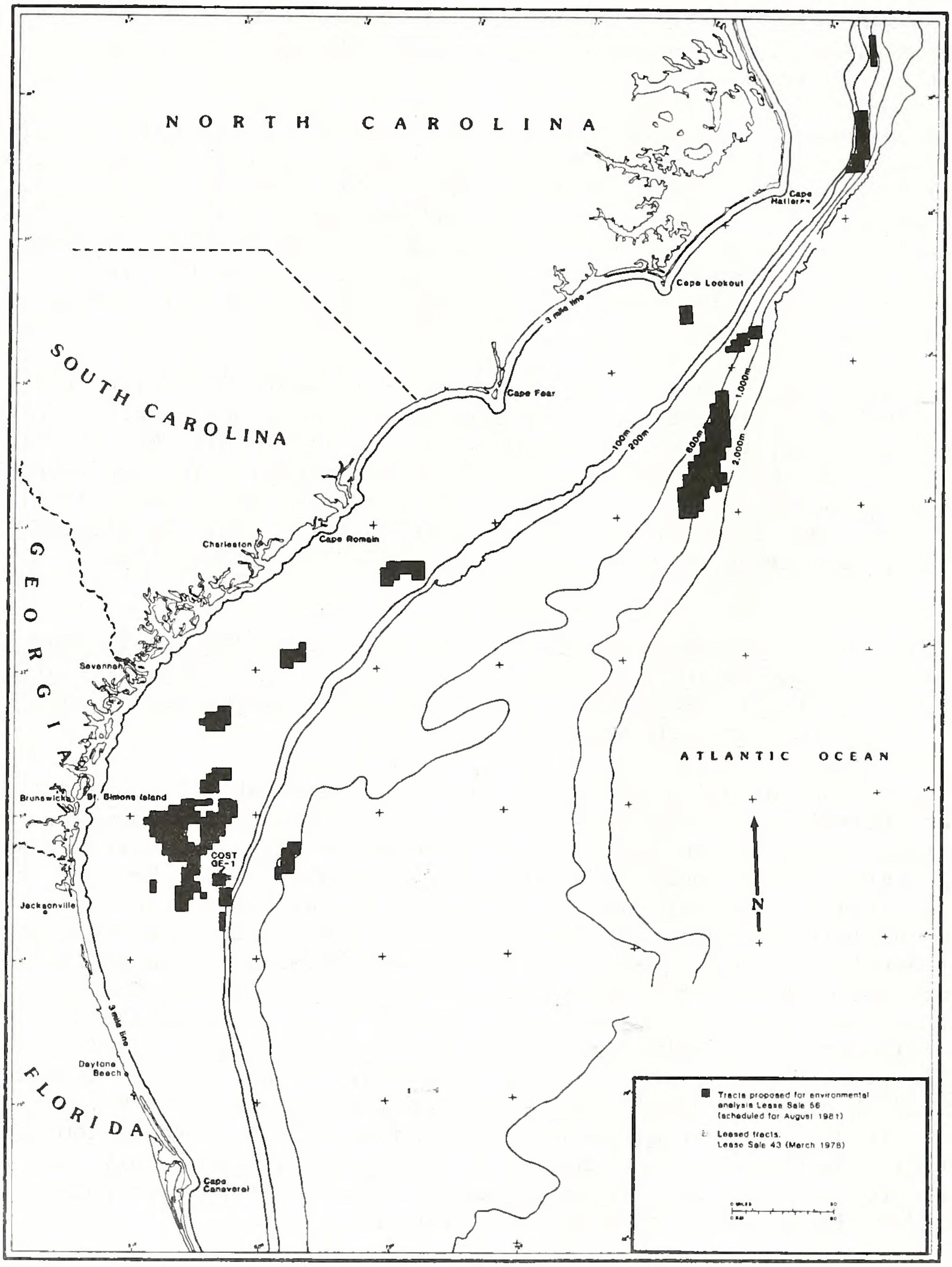
In response to local and state information needs, the Outer Continental Shelf Oil and Gas Information Program (OCSIP) was created by the OCS Lands Act Amendments of 1978 (P.L. 95-372). Under this program, the U.S. Geological Survey (USGS) and the Bureau of Land Management (BLM) are required to prepare (1) indexes of information to be used by the federal government in its OCS decision-making process and (2) regional summary data reports for use by affected coastal states in planning for the potential impacts of OCS oil and gas development.

In July 1980, a summary report was relased describing offshore activity in the South Atlantic region, which extends from Cape Hatteras, North Carolina to Cape Canaveral, Florida. One South Atlantic lease sale, No. 43, was held in the southeast Georgia embayment, and two additional sales are scheduled by BLM through 1985: Sale 56 (August 1981) and Sale 78 (January 1984) (Figure 2). Additional tracts in the South Atlantic could be offered in one or two reoffering sales scheduled for June 1982 and May 1984.

(2) No reliable analyses of the impacts of OCS development (beyond the exploratory phase) are possible until discovery of economically recoverable oil and/or gas resources and identification of their characteristics.

The volume (or daily production rate) of recoverable resources is an important determinant of the onshore impacts of offshore development. Other determinants include the location and size of the offshore reservoir and mix of oil and/or gas it contains. Until drilling takes place, however, the characteristics and amount of the oil and gas in the offshore frontier areas can only be estimated. Using its own resource estimates, the U.S. Geological Survey develops hypothetical "scenarios" and initial analyses of the level of offshore and onshore activity for each proposed lease area. No proven oil or gas fields have been discovered at this early stage of exploration in the South Atlantic; it is only possible to estimate the region's wealth in terms of undiscovered resources -- that is, quantities of oil and gas that have been estimated (based on geologic theory and information) to exist outside of known fields. To delineate possible hydrocarbon reservoirs and their commercial potential, the area must be explored by offshore drilling. Only then is it possible to calculate reserve estimates -- which are those proportions of gas and/or oil resources that can be economically extracted.

Figure 2
Leased Tracts (Sale 43) and Proposed Lease Tracts (Sale 56)



SOURCE: Jackson, Joanne Barnes, Outer Continental Shelf Oil and Gas Activities in the South Atlantic U.S. and their Onshore Impacts: A Summary Report, p. 18.

Reserve estimates permit a more accurate calculation of the level of resource development activity that can be expected in an area. Site-specific planning for offshore oil and gas production and related onshore facilities should be based on reserve estimates whenever available. Until exploratory drilling identifies the location and volume of offshore reserves, no one can accurately foresee the actual timing and intensity of offshore and onshore development activities. Figure 3 provides a rough estimate of activities off the North Carolina coast as a result of Lease Sale 56 and Lease Sale 78.

3. The greatest amount of offshore activity, and thus the greatest potential for onshore impacts, is during the field development stage.

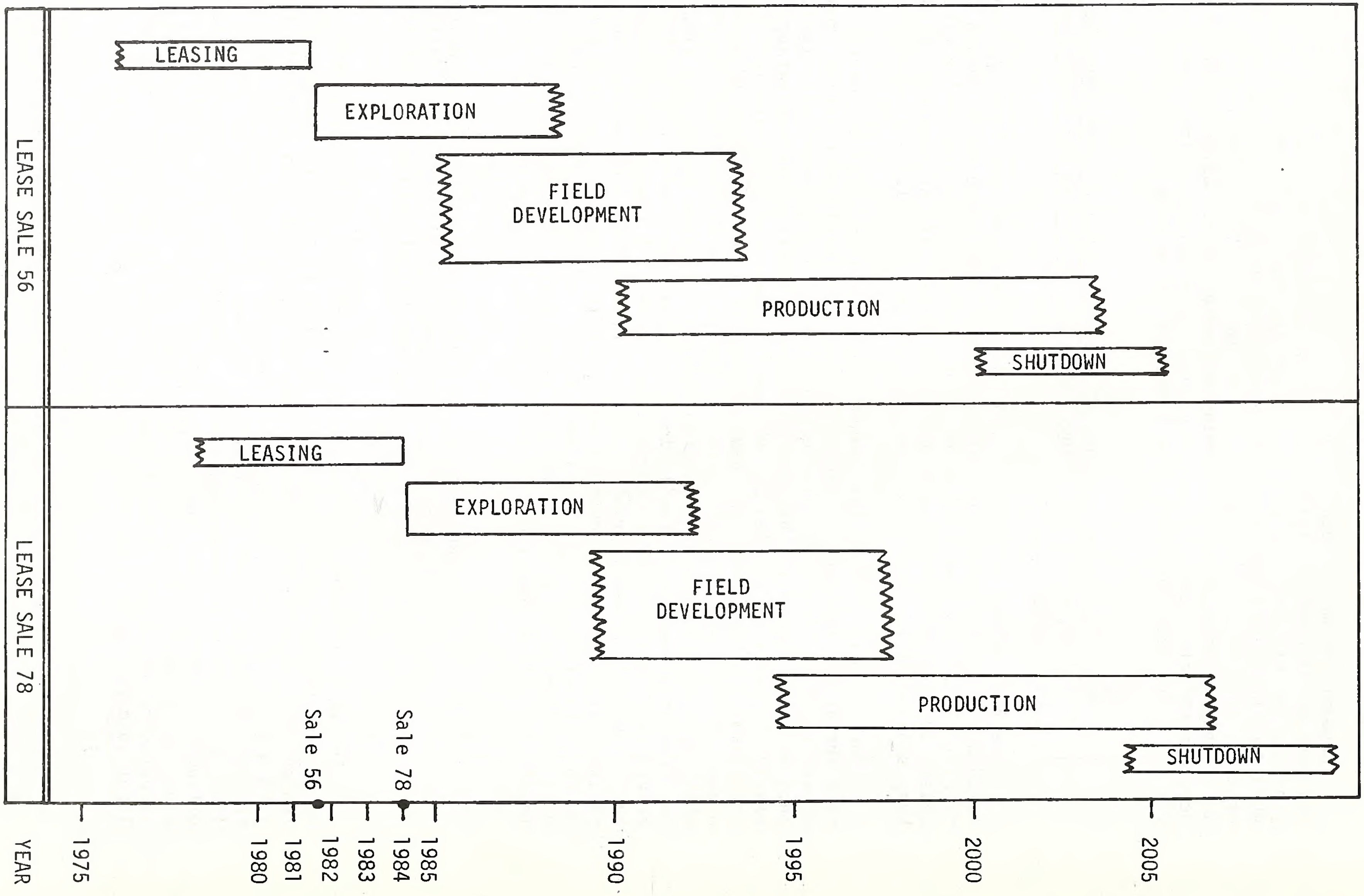
The five phases of offshore oil and gas activity are leasing, exploration, field development, production, and shutdown. The three major phases (exploration, field development, and production) may overlap since, under various lease sales, drilling may commence on different dates and the resource "finds" may keep some wells in production for years while other fields are being explored.

The offshore oil and gas industry draws most heavily on coastal communities during the field development stage. An onshore construction "boom" may create temporary high levels of employment which will taper off significantly once offshore production begins and onshore facilities are operating. Essentially all major facilities for the production stage are installed by oil companies, gas companies, and their contractors during the field development stage. Some of these facilities will locate in existing harbor facilities while some will be constructed from scratch. A large oil or gas find located far from existing harbor facilities or oil and gas production facilities will create the greatest onshore development "boom." A region with developed harbors will have fewer problems assimilating OCS-related development, especially if offshore discoveries are small or moderate. The greatest impacts to the natural environment from onshore OCS-related facilities and activities will result from site alteration for large-scale and waterfront industrial facilities rather than from the more dramatic damage potential of oil spills.

4. Staging and support facilities tend to cluster in developed harbors, providing employment and added business while often producing moderate environmental effects and conflicting with existing harbor uses.

In siting most of the onshore facilities used to support offshore operations, the oil industry looks for ports close to offshore operations that meet its physical requirements and have vacant waterfront land available for short-term leases. If these facilities are located in well-equipped urban harbors, the environmental impact is likely to be less significant than their establishment in rural coastal communities. The increase in harbor traffic during offshore exploration and field development could lead to conflicts over harbor space and to an increase in potential accidents. The ports selected and the cooperative agreements reached between the petroleum industry and state and local authorities will determine the character of these impacts.

Figure 3
Potential Timing and Intensity of OCS Development Off the Coast of North Carolina
(bar width indicates relative intensity of offshore activities and onshore impacts)



5. The scope and impacts of OCS activity will vary from region to region, depending on whether the region has established offshore activity (as in the central and western Gulf of Mexico, and the southern California area) or is a "frontier" region (as in the North Atlantic and the South Atlantic areas), whether the communities for onshore sites are urbanized or rural, and the characteristics of existing economic activity and area environmental conditions.

The "frontier" South Atlantic region (covering the area from North Carolina to Florida) is far from existing OCS support bases and has a mixture of urban harbors and rural coastal communities in areas of high environmental sensitivity. A large number of workers may need to be imported due to the lack of a large local labor pool with the specialized skills required by the offshore oil and gas industry.

Urban areas are often better structured to accommodate and absorb new industry with little stress. Rural areas generally do not possess the necessary service infrastructure, available housing supply, and labor pool. They often do not have planning resources and staffs to adequately manage the impacts of OCS development, lack adequate capital or borrowing power to fund new public services, and possess limited local development regulations and enforcement powers.

6. After a commercially valuable oil and/or gas find is made, one of the critical questions is how to transport it to shore.

Commercial quantities of gas are almost always piped ashore, but discoveries of oil require a choice between pipelines, tankers, or both to transport the oil to shore. Where feasible, pipelines are generally preferred and tend to cause less environmental and safety problems. The most significant environmental effects of offshore pipelines are the temporary and local impacts caused by the initial pipelaying operations. Tanker transportation has a higher risk of spills and environmental damage.

7. The need for large-scale facilities (oil refineries, platform fabrication yards, and petrochemical complexes) depends on a complex array of worldwide market factors rather than the development of a specific lease area.

Platform fabrication yards serve worldwide markets. Large platforms for domestic and foreign fields are built in four yards in the U.S. -- three on the Gulf Coast and one in California. Industries will attempt to use established platform fabrication yards, but if large oil and gas deposits are discovered in the Atlantic, additional yards may be developed (such as the proposed fabrication yard in Northampton County, Virginia). Future development of oil refineries and petrochemical complexes does not appear to be related to current OCS development. These facilities require a large and long-term supply of crude oil which few of the nation's new offshore fields are expected to generate. At present, the demand for new refineries in the U.S. is low since many existing refineries are operating at levels below capacity.

CHAPTER TWO:
PREPARING FOR OCS-RELATED DEVELOPMENT

In the earliest phase of OCS development, few onshore impacts will result from the survey vessels that will use existing ports. However, local and regional agencies should begin planning early for the impending onshore developments and their effects on coastal communities.

> If a community chooses to accept the OCS-related development, it has an opportunity to reap sizeable economic benefits, but it also becomes vulnerable to adverse impacts resulting from the development. To obtain maximum economic benefits and alleviate fiscal pressures and negative social and environmental impacts, a community must make informed policy decisions and then implement those policies with effective management tools and procedures. (Dornbusch, Management of OCS-Related Industrial Development, p. i)

If local decision makers are to plan for and manage OCS-related development effectively, they must:

1. understand the basics of industry operations and their impacts and understand the federal regulatory process and the information it generates;
2. establish lines of communication with relevant federal and state agencies, the industry, and local citizens;
3. evaluate the community's ability and desire to serve the needs of the oil and gas industry; and
4. review and/or establish community policies to guide onshore development.

Each local government likely to be affected by OCS-related development should designate a responsible public official to take the lead role in coordinating the local OCS impact management effort.

Understanding OCS Operations and Regulatory Processes

> Although the process of seeking and extracting offshore oil and gas is technically complex, it is quite simple in concept. Representatives of coastal communities should feel confident of attaining sufficient understanding of the operations to enable them to evaluate proposals wisely. (Dornbusch, Management of OCS-Related Industrial Development, p. I-2)

Background Readings

To develop a good working knowledge of OCS operations, onshore facility requirements and their impacts, local planners should familiarize themselves with the existing literature. Particularly instructive for planners in North Carolina are studies which describe OCS-related development and local planning responses in "frontier" areas having little or no experience with the oil and gas industry, such as those on the Atlantic coast.

Appendix A is a bibliography containing short descriptions of a variety of OCS studies and documents. The bibliography ranges from simple descriptions of OCS activities and facilities to insightful case studies and guidebooks for local planning. The following publications are particularly useful:

Baldwin and Baldwin. Onshore Planning for Offshore Oil: Lessons from Scotland.

David M. Dornbusch and Company. Management of OCS-Related Industrial Development: A Guide for Alaska Coastal Communities.

Gillman. Oil and Gas in Coastal Lands and Waters.

Jackson. Outer Continental Shelf Oil and Gas Activities in the South Atlantic U.S. and their Onshore Impacts: A Summary Report.

Macpherson and Bookman. Outer Continental Shelf Oil and Gas Activities in the Mid-Atlantic and their Onshore Impacts: A Summary Report.

National Association of Counties. Serving the Offshore Oil Industry: Planning for Onshore Growth, Northampton County, Virginia.

New England River Basins Commission. Factbook and Case Studies in OCS Planning.

These reports and others are described in Appendix A. Many are available for review at the Office of Marine Affairs in Raleigh.

Keeping Up-To-Date

Throughout the OCS development process, considerable quantities of information will become available from the federal government, the State of North Carolina, and the industry itself. Information about OCS activities will be contained in various applications, plans, reports, and notices submitted in compliance with federal and state regulations. Local planners should read and maintain a file of these documents as they become available. The various reports keep planners informed of recent developments in the exploration, development, and production processes and in federal and state OCS agencies. For example, the exploration and development plans required of lease-holding oil and gas companies must include the anticipated location and impacts of OCS-related facilities. This gives local governments more detailed information on what onshore activities are likely to occur and an early start in planning for onshore development. Chapter III describes key documents generated by the industry and federal agencies which are useful to local planners at each stage of OCS development. Each of the remaining chapters in this report contains a section on information flows, identifying the sources and timing of information generated during the separate phases of development.

North Carolina's OCS Task Force maintains a comprehensive OCS library at the Office of Marine Affairs in Raleigh. Interested individuals may arrange access to the library through the state's OCS Coordinator (see Appendix D for the address).

Establishing Lines of Communication

Not all federal, state, and industry reports will be directly channeled to local planners in the OCS leasing region. Local planners may have questions regarding OCS development that existing reports do not answer. It is essential that local planners establish contact with federal and state OCS agencies and the oil and gas industry to ensure a continuous flow of information. Petroleum industry representatives are generally available to answer specific questions. State and federal agencies are interested in providing information to local governments and receiving local input into OCS decision making. Appendix D is a directory of relevant federal and state agencies in North Carolina; the state OCS coordinator is the key contact person who channels information to local governments and other interested parties.

Evaluating the Community's Capacity to Accommodate OCS-Related Development

As a prelude to the formulation of local OCS planning objectives and actions, a community should (1) assess its ability to serve the needs of the oil and gas industry and (2) assess how the impacts of onshore development relate to local economic development, public services, and environmental protection objectives, particularly those stated in the local CAMA land use plan.

> The better a community understands its ability to serve the industry's needs the easier it will be for the industry to work with that community and the greater will be the community's chances of achieving benefits from the development while minimizing undesirable impacts . . . . By also comparing its own relative strengths and weaknesses with those of other coastal communities, local officials can judge how flexible industry can be in choosing locations for onshore sites. (Dornbusch, Management of OCS-Related Industrial Development, pp. I-7 to I-8)

This information will help local planners assess the community's chances for attracting development and the industry's willingness to modify its plans to conform to local objectives.

Petroleum companies and their contractors evaluate several general conditions in choosing a particular site for onshore development. Some of these are:

1. proximity to offshore activities and to supplies of equipment and materials
2. harbor conditions (sufficient dockside depth and frontage, minimal tide problems, adequate turning basins)
3. infrastructure and services (airport, roads, and rail service to the harbor, water supplies, waste disposal facilities, power, telecommunications)
4. developable land (adequate area, slope, stability, and bearing capacity, adjacent or accessible to port facilities)
5. labor force (for construction, for operations, and for support services)
6. ownership of the developable land and the need for parcel assembly
7. the need for zoning changes

8. potential negative environmental and social impacts, and

9. local policies regarding environmental protection, industrial development, and public services.

Communities should understand the importance of each of these factors for the types of onshore development being considered in the region. These services and facilities are not necessarily preconditions for development; in some cases, the industry can provide the service or facility itself or modify its operations to reduce the need. However, industry prefers to locate in communities where a full range of facilities and services is already available.

This preliminary assessment will help local planners (1) avoid a blind pursuit of industrial development with little consideration for its potential negative impacts, or (2) avoid a blind rejection of a potentially valuable economic activity without considering ways its negative impacts can be minimized. By identifying opportunities for and constraints to OCS-related onshore development, local planners can respond to development proposals in an informed and capable manner.

Establishing and/or Reviewing Community Objectives

A community's policies and objectives should be the basis for all of its actions regarding OCS-related onshore development. Community policies regarding OCS-related development will have to accommodate diverse interests of local residents in environmental protection, economic development, and fiscal stability. From these policies should grow a set of clearly defined objectives which will guide local leaders in assessing the local implications of state and federal OCS decisions and in reviewing local onshore development proposals. To be effectively implemented, public objectives rely on sound land use and environmental regulations, economic development programs, and capital improvements and public service programs.

Community objectives identify the community's position on issues of land use, environmental quality, the local economy, municipal finance, and local government participation in commercial ventures. Each of these issue areas is discussed below, with examples of objectives and implementation strategies a community might adopt. (Much of this discussion is adapted from Dornbusch, Management of OCS-Related Industrial Development, pp. I-10 to I-13.)

Land Use

The wise location of onshore facilities can minimize interference with other activities in the community (such as commercial fishing and recreational boating) and prevent industry-community conflicts. Through its land use policies, a community can facilitate an efficient and compact industrial operation which will serve both public and industrial purposes. The concentration of OCS support activities avoids the extra service costs associated with dispersal and limits certain adverse impacts (such as noise and congestion) to circumscribed areas. Community policies may pertain to the quality of land uses as well as their location; policies may include design criteria for industrial sites.

Sample policies:

Objective: Minimize conflicts over harbor use.

Strategy: Locate OCS-related service bases away from commercial fishing wharfs and recreational marinas.

Objective: Concentrate OCS support activities.

Strategy: Include a waterfront industrial district in the local zoning ordinance.

Environmental Quality

Local environmental protection policies can prevent damage to sensitive natural areas and cultural and historical resources. Among the potential problems local planners should consider are water pollution, air pollution, noise, visual nuisances, and solid and hazardous waste treatment and disposal. Local planners should also identify natural hazard areas and other physical constraints to industrial development in the community. Local objectives may include restricting development from geologically unstable areas and poor soils. Existing state and federal environmental regulations already cover most water quality, air quality, and waste disposal problems; nonetheless, there is still much the community can do to protect its natural environment.

Sample policies:

Objective: Prevent accelerated erosion and exposure to natural hazards.

Strategy: Restrict development from specified eroding ocean and estuarine shorelines and other unstable areas.

Objective: Minimize noise disturbance from on-site operations and materials transfer.

Strategy: Include noise performance standards or buffer zone requirements in the local zoning ordinance.

Local Economy

OCS-related operations may affect the local economy positively and negatively, and directly and indirectly. For example, local workers may be lured away from their present jobs by the prospect of higher wages (a direct effect). Their extra earnings may stimulate the local economy through the purchase of local goods and services (an indirect effect). Workers brought in temporarily from outside the community may send a large portion of their income to families "back home" instead of spending it in the community. Community policies may seek to capture the positive effects of the OCS industry's employment demands.

Sample policies:

Objective: Encourage the hiring of local workers.

Strategy: Negotiate with industry to reserve 25% of all new OCS-related jobs for local residents.

Objective: Support training programs for local workers.

Strategy: Train unskilled workers in relevant subject areas.

Municipal Finances

Communities have extensive financial interests in onshore facilities. While the developments will increase the local property tax base, they will require public services and public expenditures. Local jurisdictions are likely to face increased direct costs for water supply and waste disposal; large-scale onshore development may require expanding the capacity of schools, roads, fire and police protection, and government administration. In order to meet such costs, community financial objectives should be well-conceived and explicit.

Where publicly-owned land is suitable for OCS-related industrial development, a community may wish to participate directly in OCS activities and gain a share of the profits from development by leasing the site for onshore facilities.

Sample policies:

Objective: Avoid large capital outlays of public funds.

Strategy: Fully utilize existing public facilities (such as waste disposal sites) before developing new ones.

Objective: Avoid public subsidies of services and facilities that support OCS operations.

Strategy: Require the revenues derived from OCS activities to cover the increased capital, operating, and maintenance costs of affected public services and facilities.

Existing local objectives, regulations, and programs covering industrial development may be adequate to cover OCS-related development. Local planners need to compare their existing capacity to guide and accommodate industrial development to the particular problems and opportunities present in OCS-related development. If the existing local capabilities are not adequate, then local planners may broaden the coverage of local policies by:

1. enlarging the scope of existing industrial development plans and regulations
2. formulating special policies and plans for OCS-related activities and facilities, and
3. formulating specific area plans for sites suitable for development as onshore OCS-related facilities.

This is by no means an exhaustive list. OCS development has the potential to affect all aspects of a community, from the productivity of wetlands to the capacity of the school system. By understanding OCS activities and facilities, local planners should be able to target potentially important socioeconomic and environmental impacts in their communities which merit public action.

The actions local planners may take at each stage of OCS development are explained more fully in the next chapters. Planners should familiarize themselves with these actions and the impacts of onshore development. This familiarity will suggest possible local approaches to managing OCS-related activities and facilities before they arrive in the community; planners can plan for OCS-related development rather than merely react to it.

CHAPTER THREE:
THE STAGES OF OCS DEVELOPMENT

The offshore oil and gas development process occurs in five stages: leasing, exploration, field development, production, and shutdown. The entire development process for a given offshore field may last up to 30 or 40 years. Figure 4 shows the relative timing and activity levels of each stage. The five stages may overlap considerably during the life of a field. Field development and production depend entirely on the discovery of economically recoverable oil or gas reserves. Exploration may continue as platforms and pipelines are constructed and the field is put into production. Different lease sales may commence exploration at different dates. New production wells may be drilled while existing wells are extracting oil and gas. Different "finds" may keep some wells in production for several years after other wells are shut down.

A variety of offshore and onshore activities and facilities are required to explore and develop offshore oil and gas fields. Figure 5 outlines the different industry activities which characterize each stage of OCS development. These activities have different impacts on coastal communities and different implications for local government planning to manage these impacts.

Figure 4
Activity Levels During the Five Stages of OCS Development

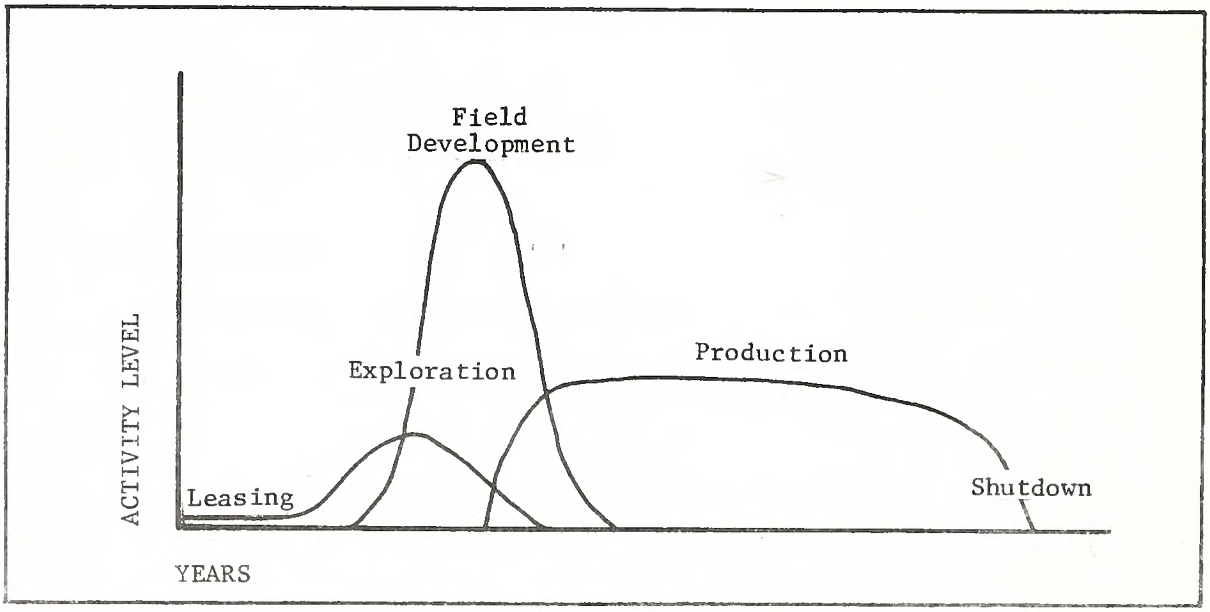
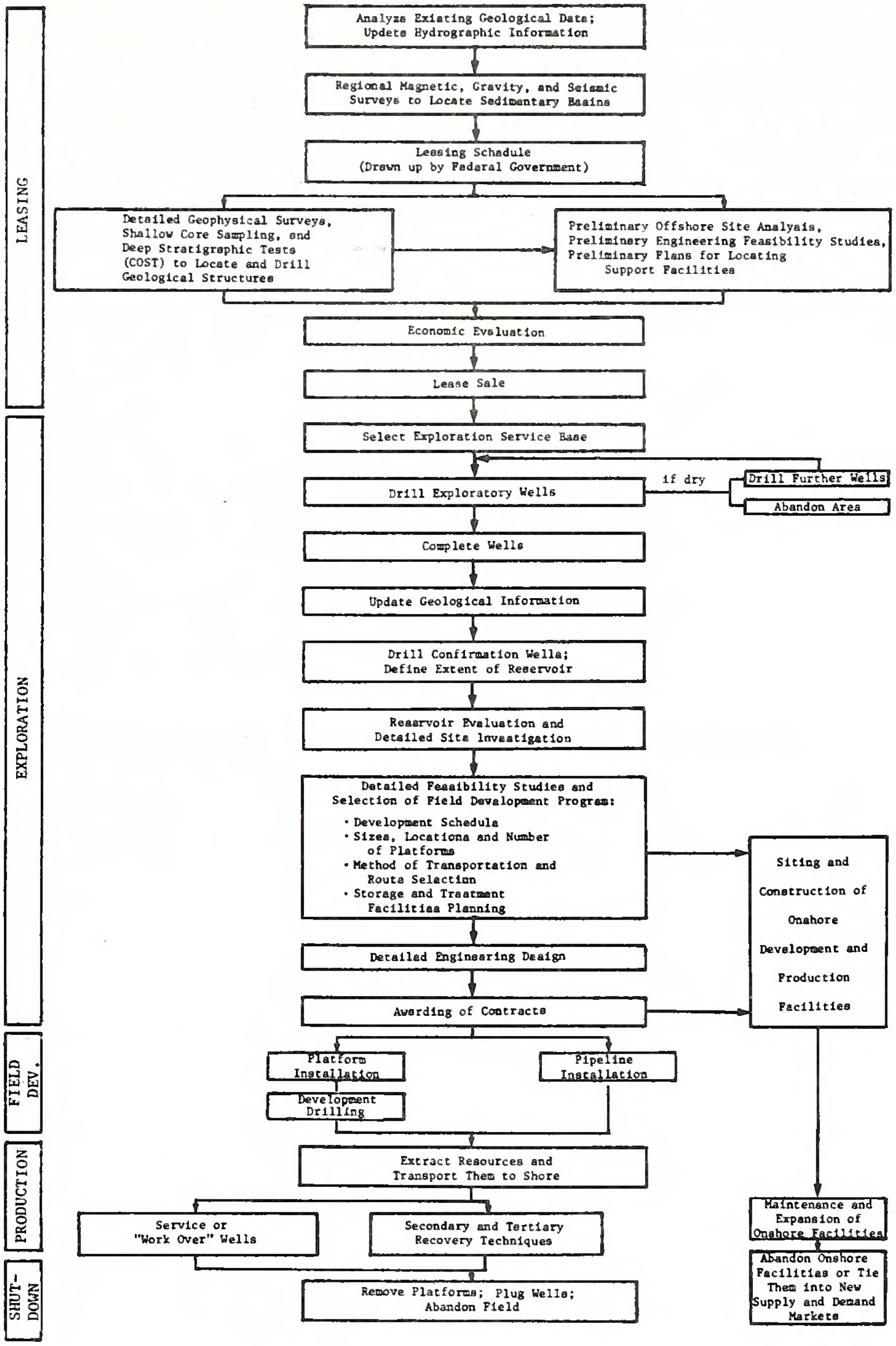


Figure 5
Industry Activities in the OCS Development Process


LEASING
EXPLORATION
FIELD DEV.
PRODUCTION
SHUT-DOWN
Analyze Existing Geological Data; Update Hydrographic Information
Regional Magnetic, Gravity, and Seismic Surveys to Locate Sedimentary Basins
Leasing Schedule (Drawn up by Federal Government)
Detailed Geophysical Surveys, Shallow Core Sampling, and Deep Stratigraphic Tests (COST) to Locate and Drill Geological Structures
Preliminary Offshore Site Analysis, Preliminary Engineering Feasibility Studies, Preliminary Plans for Locating Support Facilities
Economic Evaluation
Lease Sale
Select Exploration Service Base
Drill Exploratory Wells
if dry
Drill Further Wells
Abandon Area
Complete Wells
Update Geological Information
Drill Confirmation Wells; Define Extent of Reservoir
Reservoir Evaluation and Detailed Site Investigation
Detailed Feasibility Studies and Selection of Field Development Program:
• Development Schedule
• Sizes, Locations and Number of Platforms
• Method of Transportation and Route Selection
• Storage and Treatment Facilities Planning
Siting and Construction of Onshore Development and Production Facilities
Detailed Engineering Design
Awarding of Contracts
Platform Installation
Pipeline Installation
Development Drilling
Extract Resources and Transport Them to Shore
Service or "Work Over" Wells
Secondary and Tertiary Recovery Techniques
Maintenance and Expansion of Onshore Facilities
Remove Platforms; Plug Wells; Abandon Field
Abandon Onshore Facilities or Tie Them into New Supply and Demand Markets

The following sections of this chapter describe key aspects of each of the five stages of OCS development, including offshore activities, related onshore facilities, impacts on the local economy and natural resources, and various documents or plans which the offshore industry must submit to the federal and state governments under various regulatory programs. The descriptions of offshore activities, onshore facilities, and their impacts will familiarize local planners with the criteria the industry uses to site onshore facilities. Documents which the industry submits to the federal and state governments provide valuable information on the industry's plans to construct onshore facilities. This information will help local planners choose appropriate techniques to manage the onshore impacts of OCS development.

The Leasing Stage

The first step in locating offshore oil and gas deposits is to analyze the geological substructure of the outer continental shelf. Petroleum companies individually or collectively conduct geophysical surveys and core sampling to identify and locate favorable reservoir rocks and structural "traps" in which oil and gas may have accumulated. Knowledge of the geological structure of the offshore region is also useful in detecting fault zones and other near-surface conditions which pose possible hazards to exploration and production operations.

Industry activity during the leasing stage is usually based on the U.S. Bureau of Land Management's (BLM) overall leasing schedule. The schedule indicates the order in which frontier areas will be offered for lease. Geophysical surveys may take place for years before the lease sale. During this time, oil and gas companies will review existing geological information, update hydrographic information, and conduct offshore geophysical surveys in the offshore leasing region. They will also prepare internal marketing and production capability analyses. This information is used by BLM to prepare the leasing schedule and by industry to derive resource estimates and nominate the most promising tracts for leasing.

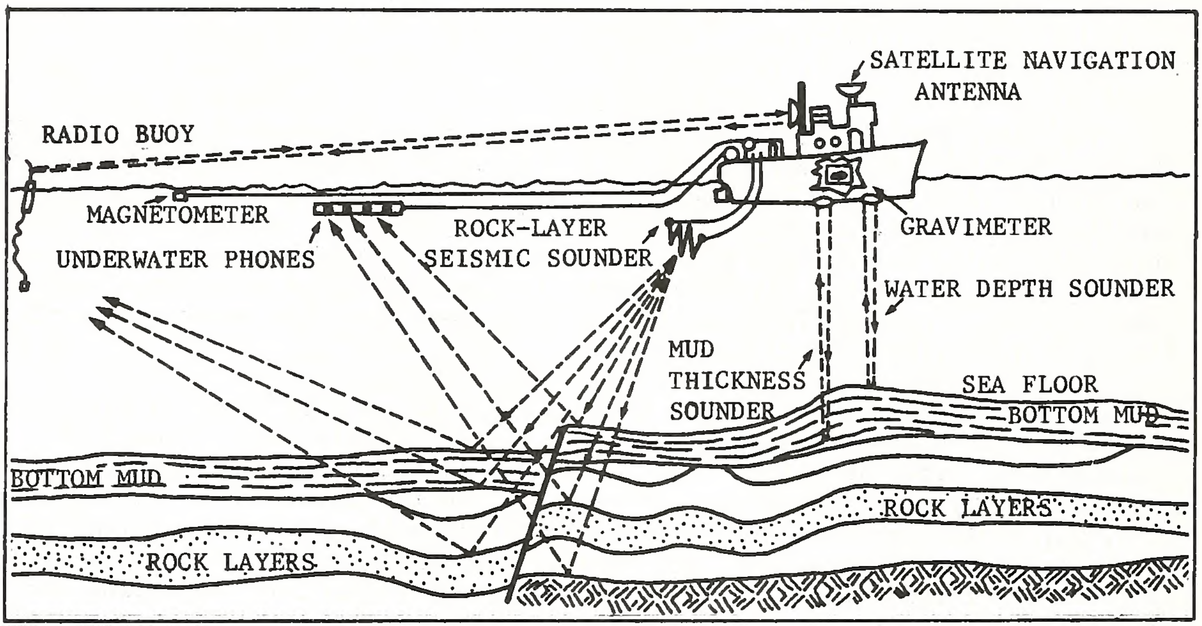
PRE-LEASE EXPLORATION AND ITS ONSHORE IMPACTS

Industry's investigation of potential offshore resource areas begins long before the leasing process begins. The federal government does not allow actual drilling for oil and gas before a lease sale but does allow other types of geophysical exploration.

The seismic survey is the principal technique used by oil companies or their contractors to identify hydrocarbon reservoirs that hold the most promise for yielding commercial quantities of oil and gas. Three types of studies help industry determine appropriate location for future exploration efforts. The studies involve:

1. potential offshore extensions of known hydrocarbon-bearing onshore formations
2. comparing the lithology of offshore formations with formations elsewhere in the world which bear oil and gas, and
3. gravity and magnetism measurements which provide a general picture of the type and depths of sedimentary rocks that lie beneath the sea floor.

Figure 6
Geophysical Surveying Equipment



A typical seismic survey involves a ship with a small crew traveling along a predetermined path or grid and towing signal-generating and recording equipment (Figure 6). A shipboard energy source (usually air or gas guns) creates a series of sonic pulses that travel through the water and are reflected by underlying rock formations. The returning sonic waves are detected by hydrophones towed behind the ship and are recorded on shipboard computers, which translate the data into vertical cross-sections of the seabed. The cross-sections are then interpreted to identify possible structural and stratigraphic hydrocarbon traps.

Another type of survey involves using a magnetic sensor, or magnetometer, which is towed behind the survey ship to detect small warps or anomalies in the earth's magnetic field produced by different types of rocks. These anomalies are analyzed to identify the structure of subsurface rocks and hydrocarbon-bearing strata. Survey vessels may also use gravity meters to measure slight changes in the force of gravity attributable to different rocks of varying densities and hydrocarbon potential.

Other types of geophysical surveys are performed by industry in addition to the deep penetration survey described above. Shallow penetration sonar studies help map sea floor topography and geology in more detail to aid in selecting specific sites and techniques for future offshore drilling and production. They can locate faults, mudslides, and other geological hazards on or near the ocean floor.

The geophysical survey data collected by one or more of the techniques described above may be supplemented by shallow core drilling to obtain samples of rocks on or near the ocean floor. These studies indicate:

1. the age of the rock

2. the stratigraphic relationship of different rock layers, and

3. their mechanical properties (such as load strength and compressibility), necessary for designing platforms and pipelines for specific locations.

Pre-lease exploration may include the drilling of a deeper, Continental Offshore Stratigraphic Test (COST) well, especially in regions with expansive geological structures. This test, drilled from a mobile rig, may penetrate up to 16,000 feet of rock. According to U.S. Geological Survey regulations, COST wells must be drilled "off-structure" (away from where oil and gas collect). No direct testing for oil and gas is permitted before the lease sale. Only one COST well is drilled in a proposed leasing region. Core samples taken during COST drilling are used to confirm conclusions about potential source rocks and reservoirs, the structural composition of the ocean floor, and other factors which indicate possible oil and gas accumulations in adjacent geological structures. COST drilling precedes the definition of specific leasing tracts and lease conditions which govern post-leasing exploration and development.

The companies involved in the COST effort share the information gained and the multi-million dollar costs. In 1976, two deep stratigraphic tests, financed by a consortium of more than 20 companies, were completed in the Baltimore Canyon Trough (off the New Jersey coast) and in the Georges Bank (off Cape Cod). In 1977, another COST well was drilled off the coast of Georgia by a consortium of 25 companies. A COST well was scheduled to be drilled in October 1980 approximately 93 miles due east of Wilmington, North Carolina; however, the well was not drilled.

OCS exploration and development activities are generally managed by the U.S. Geologcial Survey. COST wells and associated exploration activities require specific permits from the U.S.G.S., the Coast Guard, and the Army Corps of Engineers. In many respects, these are the same permits required for post-lease exploration (see The Exploration Stage). The Bureau of Land Management (Department of the Interior) is responsible for selecting lease tracts and conducting the lease sale.

Pre-lease exploration activities are not likely to have significant onshore impacts. Geophysical survey vessels have no discernible impacts on coastal communities. The survey ship is similar in size (150 to 200 feet long) and needs to a commercial fishing vessel. It docks to take on supplies and fuel at existing port facilities and requires no unusual cargo-handling equipment. Shipboard labor is contracted with the vessel, offering few, if any, local employment opportunities. Onshore businesses that provide the services needed by survey vessels, such as fuel and food, may benefit from a small increase in business.

If conducted under established regulations, the offshore surveys do not affect living resources. Before the perfection of modern techniques, dynamite was frequently used to generate sound waves and caused fish kills in the vicinity of the testing. Modern seismic techniques have not caused any documented adverse impacts on fish and other resources.

COST well drilling rigs are identical to the rigs used in post-lease exploration and have the same onshore impacts. The impacts of exploratory drilling are described later in this chapter.

In addition to offshore geophysical surveying and COST drilling, companies may begin to look for and acquire sites for onshore development before the lease sale, depending on their confidence that commercial quantities of oil and gas will be discovered. This is a strong indicator of future OCS-related development in a community.

THE LEASING PROCESS

Each OCS lease sale follows specified procedures and generates several documents. Throughout the federal OCS leasing process, the Bureau of Land Management coordinates with federal, state, and local agencies, institutions, public interest groups, and concerned individuals in order to involve others in the planning and decision making for any federal OCS action. This coordination is mandated by the Outer Continental Shelf Lands Act and the National Environmental Policy Act.

The steps of the lease sale and the information generated in them are:

1. Environmental Baseline Studies -- In addition to geophysical and geological surveys of OCS resources, environmental baseline studies are conducted in frontier leasing areas by the Department of the Interior. The studies establish baseline environmental data against which any changes caused by OCS exploration and development can be measured through an ongoing monitoring program.

2. Resource Reports -- After an area has been scheduled for a lease sale, the Bureau of Land Management requests resource reports from other units within the Department of the Interior, including the Geological Survey, the Fish and Wildlife Service, the National Park Service, and the Heritage Conservation and Recreation Service. BLM also solicits reports from other federal agencies, including the National Oceanic and Atmospheric Administration, the Coast Guard, the Environmental Protection Agency, and the Department of Energy. Government agencies in affected states may also be asked to submit resource reports which identify the region's environmental sensitivity and potential conflicts between OCS development and other resource uses, such as fishing, recreation, and transportation.

3. Call for Nominations and Comments -- The purpose of the call for nominations is to identify tracts of interest to the oil and gas industry, as well as tracts that should not be leased or should be leased only with conditions to protect environmental resources. Copies of the call for nominations are prepared in BLM's Washington office and sent to the governor of each affected state two or three days prior to publication of the call notice in the Federal Register. The state government, local governments, and any other interested parties within the state may comment directly to BLM to nominate tracts, suggest tracts which should not be leased, and suggest lease stipulations.

4. Tract Selection -- The Department of the Interior uses the information and comments from resource reports and the call for nominations to select specific tracts for leasing. The selected tracts are studied further in the environmental impact statement for the proposed lease sale. The Department of the Interior has designed the tract selection process (a) to

choose those tracts with the greatest production potential, (b) to avoid obvious hazards to other resources, (c) to test additional prospective geologic structures and trends, and (d) to protect tracts threatened by oil and gas drainage attributable to pumping on other tracts.

Prior to the deadline for receiving nominations and comments, the affected states are contacted by BLM's OCS manager, who requests that a governor's representative (normally the state's member of the OCS regional technical working group or the state's OCS coordinator) attend the environmental briefing and tract selection meetings. Each state is offered the opportunity to comment on the sensitivity of onshore, nearshore, and offshore environments to OCS development. Maps indicating tracts of interest to industry are delivered to each governor; these assist the states in preparing for the meetings.

5. Tentative Announcement of Tracts -- The Director of BLM informs the governor of each affected state by telegram about the forthcoming announcement of selected tracts. This is followed by a mailing of copies of the tentative tract list and press release. BLM's OCS Manager informs each state representative by telephone of any significant changes to the tract lists.

6. Stipulation Meetings -- Stipulations are attached to any tract lease which has the potential for causing negative environmental impacts. A geological stipulation may be attached to a lease, but hazardous conditions are not entirely known until the USGS has had sufficient time to gather information on geological hazards (usually 60 days prior to publication of the Final Environmental Impact Statement). On the basis of this hazards report, recommendations are made by the USGS for the deletion of tracts or the attachment of lease stipulations. The state plays a key role in drafting lease stipulations through the OCS regional technical working group.

7. Oil Spill Models -- The USGS develops these models to estimate the probabilities for oil spills in the proposed leasing area. This information helps assess the environmental impacts which could be caused by an oil spill.

8. Public Scoping Meetings -- Public scoping meetings present an opportunity to identify important environmental and socioeconomic issues related to the proposed lease sale. The meetings are held by BLM in cities which the state representatives determine will likely attract the greatest public participation.

Legal notices and news releases printed in area papers outline general information about the proposed sale and the forthcoming scoping meetings. Area radio and television stations are mailed copies of the news releases and requested to publicize the meetings. A general mailing is sent to all recipients of past OCS environmental impact statements and to institutions and individuals who the BLM believes will have an interest in the proposed sale.

9. Draft Environmental Impact Statement (DEIS) -- The Draft EIS is the main consolidated source of information on the possible impacts of OCS development on coastal communities. The Department of the Interior prepares site-specific impact statements for each proposed OCS lease sale.

A Preliminary Draft EIS (PDEIS) is distributed by BLM's OCS Manager to state representatives for their review and comment. Comments received on the PDEIS are considered in preparing the Draft EIS. Once the tracts are selected for a proposed lease sale, BLM proceeds to prepare the DEIS in accordance with Section 102 of the National Environmental Policy Act. The impact statement must include a description of the proposed action, a description of the existing environment (both marine and onshore), a detailed analysis of possible adverse short-term and long-term impacts on the environment, proposed mitigating measures, an assessment of alternatives to the proposed action, and a record of consultation and coordination with other parties. The Draft EIS is submitted to the Council on Environmental Quality (CEQ) and made available for public review and comment. On the day DEIS availability is announced in the Federal Register, the OCS Manager delivers copies to the governor's office and designated clearinghouse of each affected state. The State of North Carolina has arranagements for the broad distribution of environmental impact statements relating to the state's coastal region. Copies of impact statements go to major public libraries, DNRCD field offices, and Marine Resources Centers.

10. Public Hearing -- The Bureau of Land Management routinely provides the opportunity for local participation in the OCS public hearings. Dates and locations of the public hearings are announced in the Federal Register and in newspapers of general circulation in the state's coastal zone. Public hearings are conducted after a review and comment period of at least 45 days. The hearings are followed by an additional 15 days during which the public may submit comments on the DEIS to the Bureau of Land Management. Verbal comments at the hearing should be followed up with a letter conveying the same comments to BLM's OCS Manager.

11. Final Environmental Impact Statement (FEIS) -- All comments received on the DEIS and at the public hearings are considered in preparing the Final EIS. The FEIS is distributed to the Council on Environmental Quality, depository libraries, and the general public along the same pattern as the Draft EIS.

12. Secretarial Issue Document (SID) -- At the same time the FEIS is prepared, an SID presenting significant issues and identifying alternative actions is developed for the Secretary of the Interior. The SID brings to the Secretary's attention all factors associated with the proposed action. These include potential economic and social impacts of the proposal as well as environmental and physical factors. The SID and the Final EIS provide the necessary information to the Secretary for making decisions on various sale options, including whether or not to hold the sale. The SID is normally provided to the governor's office as an attachment to the Proposed Notice of Sale.

13. Proposed and Final Notices of Sale -- If the Secretary decides to go ahead with the sale, the OCS Manager provides the governor of each affected state with a copy of the Proposed Sale Notice for further review and comment. The Department of Energy is also supplied with a copy for its review and comment. BLM publishes the Proposed Notice of Sale in the Federal Register. This notice includes information on sale procedures and the method of bidding designed by Interior's Office of Policy Analysis and the Department of Energy. Copies of the notice are sent to the governor of affected states for a 60-day review and comment period. After 60 days, BLM makes a final decision regarding the method of bidding, lease stipulations, and all terms and conditions of the sale. BLM then issues a Final Notice of Sale, which is reviewed principally by the Fish and Wildlife Service, the USGS, and the Department of Energy. The Final Notice must precede the lease sale by 30 days.

14. Lease Sale -- At the lease sale itself, sealed industry bids for individual tracts are opened, read, and recorded. After an assessment is made by the BLM, USGS, and the Department of Justice, leases may be awarded to the highest qualified bidders (with any stipulations). The Secretary of the Interior reserves the right to withdraw tracts from the sale, as well as to reject bids received. Bids are accepted or rejected by the Department of the Interior based on detailed resource estimates prepared for each tract by the USGS and other Interior agencies.

The Bureau of Land Management issues a lease contract for each accepted bid. The contract grants the lessee the right to conduct drilling operations and extract oil and gas from a specific offshore tract. Each tract covers an area up to 5,760 acres (nine square miles). The lessee has five years to conduct approved drilling or to produce oil and gas on the tract; otherwise, the lease is forfeited. If the lessee discovers oil or gas, the Department of the Interior will extend the contract as long as approved drilling or production operations continue.

There are approximately 22 months between the Call for Nominations and and the actual lease sale, which signals the beginning of the exploration phase. Exploration activities typically begin six months to a year after the lease sale. In June 1981, a major effort began to accelerate and streamline lease sale procedures; some steps may be changed, lumped together, or eliminated.

15. Environmental Monitoring Studies -- Environmental monitoring studies are conducted in the vicinity of certain tracts as a result of lease stipulations, as part of EPA and Coast Guard permit programs, and as part of BLM's ongoing OCS Environmental Studies Program. Monitoring of biological and some chemical aspects of the environment will be conducted at "live bottom" habitats off Georgia, South Carolina, and North Carolina as part of the South Atlantic OCS Living Marine Resources Study. Geological and geophysical studies are conducted yearly via the South Atlantic OCS Geological Studies Program. Physical, oceanographic, and meteorological studies are performed

through the South Atlantic OCS Physical Oceanography and Data Buoy programs. Unique conditions on the Blake Plateau, including geological hazards and biological communities, are being examined in the South Atlantic/Blake Plateau Hazards Mapping Study. Additional studies may be performed in the vicinity of selected sensitive biological environments as a result of stipulations on certain tract leases. Other federal agencies, state agencies, and industry representatives may provide input to these studies through Secretarial Order 2974, BLM's Intergovernmental Planning Program, and the environmental issue identification ("scoping") process.

Local and Regional Participation in Lease Sale Procedures

Participation in the Call for Nominations (Step #3 above) allows local and regional governments, planners, and citizens to identify tracts which should not be considered for leasing ("negative nominations") or which should have special conditions imposed on them. The greatest opportunity for public comment and the identification of important social, economic, and environmental issues related to a proposed lease sale is at the public scoping meetings (Step #8). Meetings are generally held in cities and towns that may be greatly affected by the sale and often draw large crowds of residents and officials. The scoping meetings provide local governments and planners with a public forum to air their views to state and federal officials and to assess the mood and concerns of local residents. Planners and other interested parties may also participate in tract selection meetings (Step #4) and review and comment on all aspects of the draft environmental impact statement (Steps #9 and #10).

The Exploration Stage

The offshore oil and gas industry uses information gathered during the exploration stage to plan the timing and scale of field development and production. Exploratory drilling determines if offshore oil and gas exist in "commercial" quantities and delineates the size of offshore hydrocarbon fields. Exploratory drilling begins with a relative uncertainty of success, especially in a new leasing region where geological information is incomplete. Each additional exploratory well increases the information base and allows better placement of the next well. The amount of oil and/or gas present under an offshore tract will determine the level of exploration activity. If abundant resources exist, exploration may continue into the field development stage. If resources are insignificant or not present, exploration may cease after five years or less. The exploration stage generally lasts up to seven years after the lease sale.

In addition to the actual drilling, industry activity during the exploration stage includes additional geophysical surveys to help locate favorable geologic structures. The offshore oil and gas industry also prepares various internal development projections, financial estimates, and preliminary field development plans. Companies must submit exploration plans to the USGS and submit various permit applications and notices of support activities to various federal and stage agencies. (The various documents required of the oil and gas industry during the exploration stage are described later in this chapter.) The industry will establish onshore bases of operation and, depending on its confidence in offshore reserves, begin purchasing land or land options onshore for field development and production facilities.

Federal regulatory responsibilities during exploration rest mainly in the U.S. Geological Survey, which reviews and approves exploration plans, issues drilling permits and monitors drilling procedures. The Environmental Protection Agency issues pollution control permits. The Coast Guard and the Army Corps of Engineers regulate navigational safety and potential navigational obstructions.

Local and state regulatory responsibilities mainly concern the siting and operation of service bases and other onshore support facilities, managing their employment and environmental impacts, and providing public services. Local and state agencies may also review and comment on the documents that industry presents to the federal government.

Significant development of onshore facilities first appears during the exploration stage. As a general rule, the oil and gas industry will develop no completely new facilities during the exploration stage; temporary service bases tend to locate at existing harbor facilities, while repair services and general support services tend to come from firms which already exist in the community. Industry strategies during the exploration stage emphasize minimal capital investment in onshore facilities until the discovery of substantial offshore hydrocarbon reserves. The following section discusses the community impacts of exploratory drilling methods, temporary service bases, repair and maintenance yards, and general support services.

EXPLORATION ACTIVITIES AND THEIR ONSHORE IMPACTS

Exploratory Drilling

Exploratory drilling occurs after seismic surveying has determined that a positive potential for oil and/or gas exists. The lease sale gives the lessee exclusive privileges to drill, extract, and dispose of oil and gas deposits in a tract for at least five years or as long as oil and gas may be economically produced from the tract. The petroleum company is obligated to proceed with the tract exploration in a diligent manner or run the risk of losing development rights to the tract.

Exploratory drilling determines the location and extent of offshore fields and estimates the quantity of oil or gas they contain. It differs from production drilling, which retrieves commercial quantities of crude oil identified by exploratory drilling. It also differs from Continental Offshore Stratigraphic Tests (COST wells), which provide information on the types of rocks, layers, and formation pressures in a leasing region.

Offshore oil exploration today is more complex and more expensive than operations 20 years ago. Early offshore wells were drilled in relatively shallow and protected waters. As exploration moved farther offshore, it was necessary to use larger steel platforms that were permanently affixed to a specific site by driving piles into the shallow sea floor. The cost of a fixed platform, especially the expense and difficulty of moving it, reached a point where it could only be economically used for production purposes; new mobile rigs were developed for exploration. Most oil companies do not own drilling rigs; instead, they contract for rigs and drilling crews from a drilling company. The equipment and crew drilling a hole (Figure 7) belong to the drilling company; the hole belongs to the oil company.

The three major types of drilling rigs used in offshore exploration are (1) jack-up rigs, (2) semi-submersible rigs, and (3) drill ships. The jack-up rig is a floating, barge-like hull that carries a deck with drilling equipment and crew quarters (Figure 8). Three or four legs, each up to 400 feet long, are fitted vertically through slots in the hull. The legs are drawn up while the jack-up is being towed to the drilling site. When the rig is in place over the well site, the legs are lowered until they reach the sea floor. The deck is jacked up out of the water until it is beyond the reach of most anticipated waves. Unlike the other exploration rigs, a jack-up rig is secured to the sea floor to enhance its stability and its resistance to wave action. Preparing the jack-up for a move to a new location and securing it to the sea floor can take several weeks, depending on sea and sea-floor conditions. The dimensions and designs of jack-up rigs vary according to the weather conditions and water depths. Most jack-up rigs operate in calm conditions and in water up to 375 feet deep. They are located in shallower

Figure 7
Offshore Drilling Crew

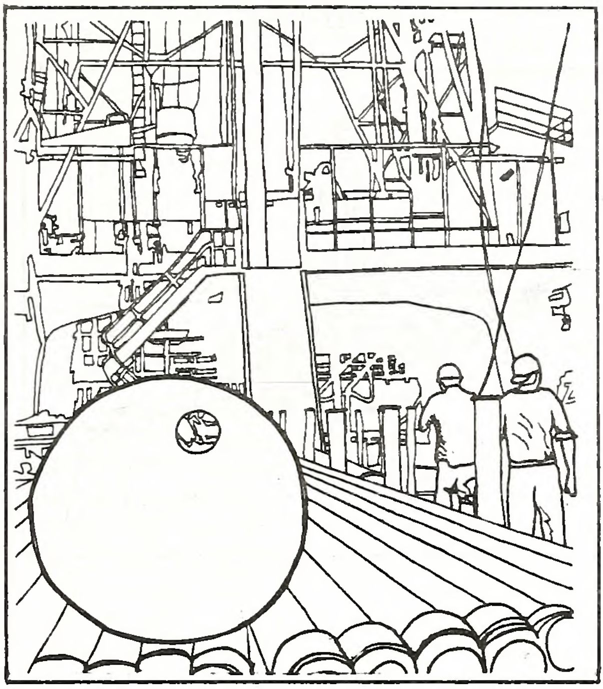
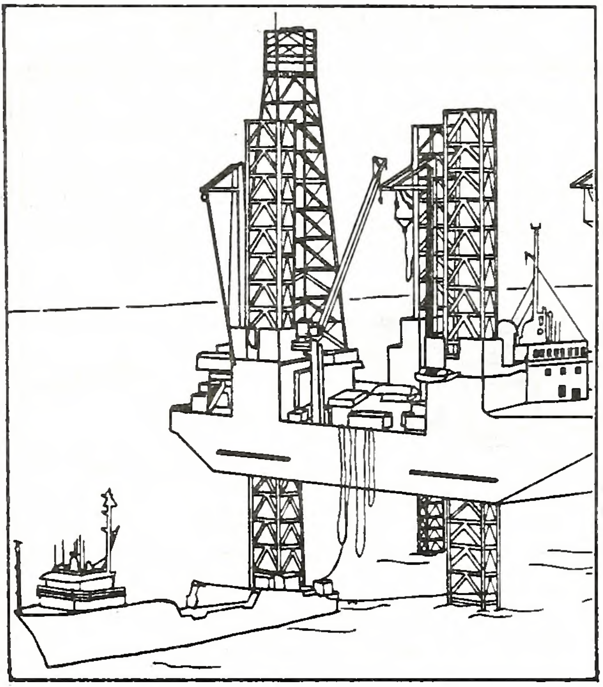


Figure 8
Jack-up Rig



water in areas with rough winter conditions. Jack-up rigs are built and serviced at existing ship yards and other coastal steel fabrication facilities. A typical rig has a hull that is about 230 feet long, 230 feet wide, and 25 feet deep, with accommodations for almost 80 crew members and a drilling penetration capability of 25,000 feet (Clark et al., Recovery Technology, p. 70). The rig normally requires a towing draft of 20 to 30 feet. Jack-up rigs are extremely stable and provide a secure drilling position when used in the appropriate depths. Jack-up rigs constitute roughly forty percent of the world's offshore exploratory fleet.

The semi-submersible floats, rather than rests on the sea bottom, and is designed to minimize the heave, pitch, and roll from waves (Figure 9). The major buoyant support for the semi-submersible is in pontoons and risers which ride on and above the surface when a semi-submersible is moving. The pontoons are sunk well below the waterline by adding ballast when the rig reaches the well site. A restricted area of 1/4 mile to two miles surrounding a rig may be required as a buffer zone to prevent fishing and other boating accidents with the rig. A semi-submersible can be anchored like a barge or dynamically positioned like a drill ship. Semi-submersibles can be rather large. One vessel, for example, has a square working platform 200 feet on a side, mounted on six hollow steel columns each 26 feet in diameter, which are in turn mounted on two pontoons, each 355 feet long, 36 feet wide, and 22 feet

Figure 9
Semi-submersible Rig

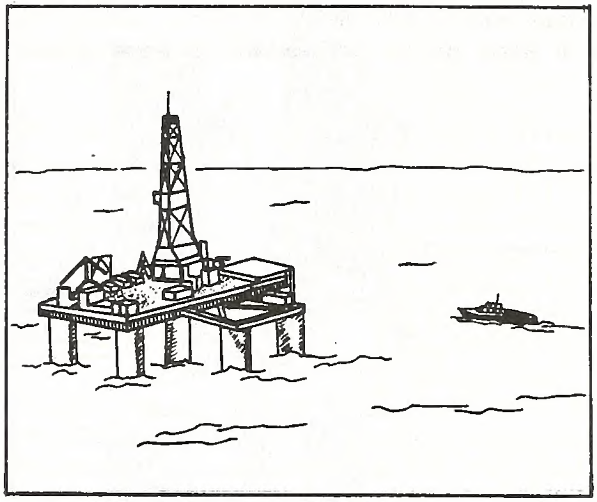
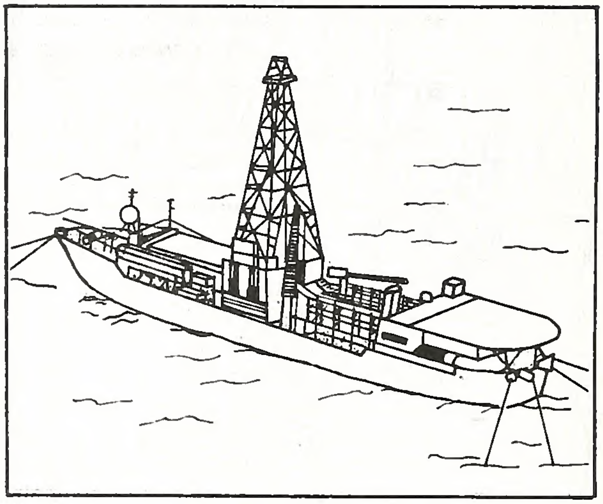


Figure 10
Drill Ship



deep (Clark et al., Recovery Technology, p. 67). Semi-submersibles are usually towed to a drilling site, though newer semi-submersibles are often self-propelled. They require large facilities for construction and servicing and a towing draft of 20 to 30 feet. Semi-submersibles usually operate in water depths of 300 to 1,500 feet, though some units currently under construction are designed to operate in 3,000 feet.

The drill ship is self-propelled for great mobility, and anchored or dynamically positioned while drilling (Figure 10). The drill operates from a derrick through a hole in the center of the ship. Various internal compartments provide crew quarters and storage space for equipment and supplies. Modern drill ships are more stable than their predecessors. For example, the Glomar 40, a 450-foot ship displacing 14,500 tons, is designed for operations in water ranging from 100 feet to 3,000 feet deep (Clark et al., Recovery Technology, p. 67). It can maintain drilling operations in 60-mph winds and 50-foot waves. A sophisticated technique known as "dynamic positioning" handles surge and sway problems on the drill ship. Automatic steering propellors, or "thrusters," keep the platform in proper position over the well. Drill ships with these and other technological features offer considerable mobility and deep-water drilling capability. They are, however, the type of rig most affected by poor weather and high wave action.

The exploration techniques employed offshore are similar to land-based methods that have been developed over the past 75 years. The only real difference is the specialized hardware and associated industries which developed to meet the needs of deepwater drilling. It is not possible to predict which type of drilling rig will be used in each OCS leasing area. The selection will depend primarily on the availability of equipment and the characteristics of the drilling site (including water depth, sea state, and the condition of the sea floor). Drill ships have good mobility and can operate in waters over 1,500 feet deep. Jack-up rigs have less mobility, but excellent stability; they are generally restricted to a maximum water depth of 375 feet. Semi-submersibles lie between jack-up rigs and drill ships in mobility and stability. The choice of rig for a particular OCS site is based on a tradeoff between the demands of mobility and water depth capability. If only a few wells, or wells in shallow water, are to be drilled, mobility might be sacrificed for the greater stability of jack-ups. However, if numerous wells or deepwater wells are to be drilled, a floating rig will be more feasible. The depth of current lease sites off of North Carolina will require floating rigs.

Impacts on the Local Economy

The primary onshore effect of exploratory drilling is on employment and wages. Personnel requirements for semi-submersible rigs may include three people onshore, four crews of 36 men each working on the platform, two contract service crews of 30 persons each, and ten marine personnel (Clark et al., Recovery Technology, p. 72). Total employment, therefore, may be over 200, about half of which are on the rig at any one time. Employment per rig varies with the type of equipment rather than the nature and location of the frontier area. For one Mid-Atlantic lease sale, 80 employees (37 percent) were estimated to be hired locally. Another 87 individuals were estimated to maintain temporary local residences while the drill ships worked the site. The remaining 50 individuals were predicted to commute home during the seven days they were off duty.

Impacts on Natural Resources

Exploratory drilling can have potentially major fish and wildlife impacts from (1) the removal of ocean bottom habitat, (2) drill cuttings and other discharges from the rig, and (3) pollution caused by oil spills from well blowouts. (Accidental releases of gas are considered to be ecologically inconsequential.) The principal environmental problem will be meeting federal pollutant discharge standards for the disposal of drill cuttings, drilling muds, and brines. Solid wastes are returned onshore for disposal. Offshore exploratory activities (seismic work and exploratory drilling) involve such minor disturbances to marine life and human uses of the ocean that they are not discussed here. Exploratory rigs have the necessary drilling equipment on board, but must be supplied from onshore service bases by service boats and helicopters. The boats bring drilling muds and drilling pipes on a regular basis if the distance from shore is not excessive. Helicopters may be employed for longer distances when too much time would be consumed in boat transit. Helicopters are a quick, efficient means of contact with the rig. Crewboats or helicopters are employed to change the drilling rig crews; this usually occurs every seven days or two weeks, but varies between projects and companies. Food is brought out at these changes, and solid waste is collected from the rigs. Sewage is treated on board the rig or drill ship and discharged into the sea. Since exploratory rigs are mobile, they have no specific site requirements. The supply boats, rigs, and helicopters are onshore service bases, which do have site requirements.

Temporary Service Bases

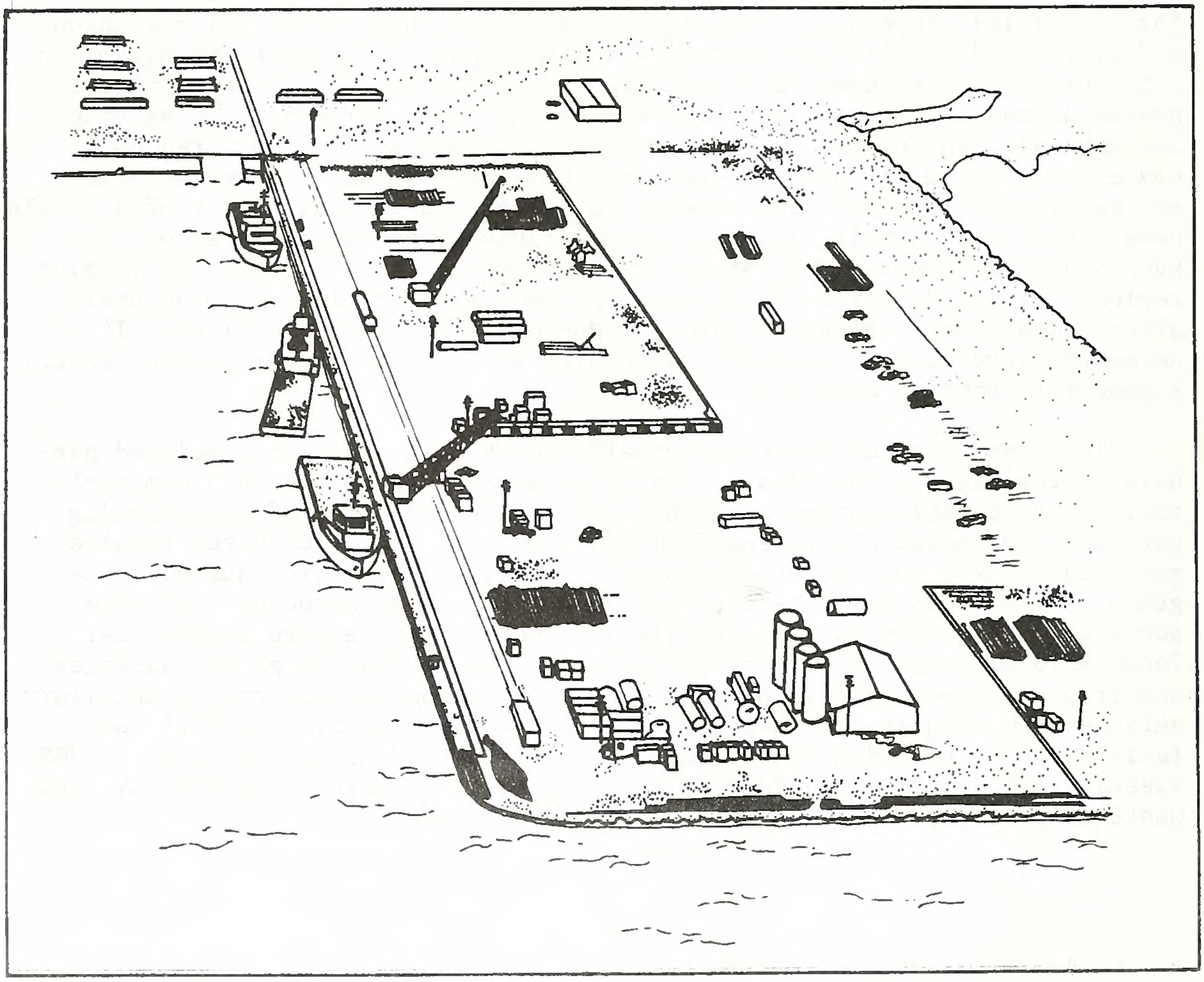
The temporary service base is the staging area established by an oil company or independent service contractor for shipping equipment, supplies, and personnel to offshore sites during exploratory drilling. The base may include berthage space for 180-foot to 200-foot supply and crew boats, dock space for loading and unloading supplies (mechanical equipment, drilling mud, etc.), warehouses, open storage areas, fuel tanks, buildings to house supervisory and communications personnel, and a helipad.

Selecting a support base location centers on finding an adequate site which can be rapidly developed when needed to support offshore operations. In a frontier region that contains ample ports, each major drilling company will identify two or three potential ports which can meet the needs for setting up a temporary base of operations. The parameters for selecting the initial site may include available facilities, community attitudes, costs, long-term development potential, and the availability of short-term leases for commercial property. Recognizing the uncertainty facing oil companies, a drilling mud supplier or support service company will sometimes establish a temporary service base in a port that is convenient to the lease area and possesses the necessary site characteristics. The mud company or service company may then "court" one or more oil companies by offering free dock space in exchange for the contract for drilling mud and/or other supplies and services. This may lead several oil companies to operate out of a single base. Since the service industry is so highly competitive, three or four such bases may possibly be set up in different ports throughout the leasing region. Siting decisions for temporary bases are normally not made until after a lease sale, although land options may be purchased earlier. If a permanent service base already exists within 100 miles of the leased tracts, a temporary base is unlikely.

Temporary service bases are usually located at existing developed harbors. Proximity to the offshore field is a major criterion in a company's search for suitable harbor space because of the high cost of transporting personnel and materials to and from drilling rigs. Service bases require year-round ocean access, wharf frontage, an adequate turning basin, navigable channels (15 to 20 feet), and uncongested inner harbors. Existing ports are not always able to readily accommodate OCS service facilities. International shipping harbors may be geared to special cargo or passenger operations. Pleasure boat harbors are generally unable to provide ancillary services and adequate channels. A deep-sea commercial fishing port has facilities for handling ships comparable in size and characteristics to OCS vessels, but may be congested. The availability of water, electricity, and waste disposal services are also important considerations.

Service base size and the level of vessel activity are functions of the number and kinds of offshore rigs used for exploration. Temporary service bases are fairly small operations, typically occupying five acres of waterfront land for each rig being serviced (Figure 11). Approximately one and one-half acres per rig are used for open storage, fuel storage, and warehouses. One-half acre per rig is used for offices and operation space. One acre per rig is used for a helicopter pad. The base requires approximately 200 feet of wharf frontage per rig, with a water depth of 15 to 20 feet. Economies of scale arise in dock space, storage space, office space, and helicopter space when more than one or two rigs are drilling offshore. Each boat and helicopter can serve more than one rig, depending on how far offshore and how close together the rigs are. Temporary service bases may be set up at existing public port facilities. One or more office trailers may be brought in where suitable buildings are not available.

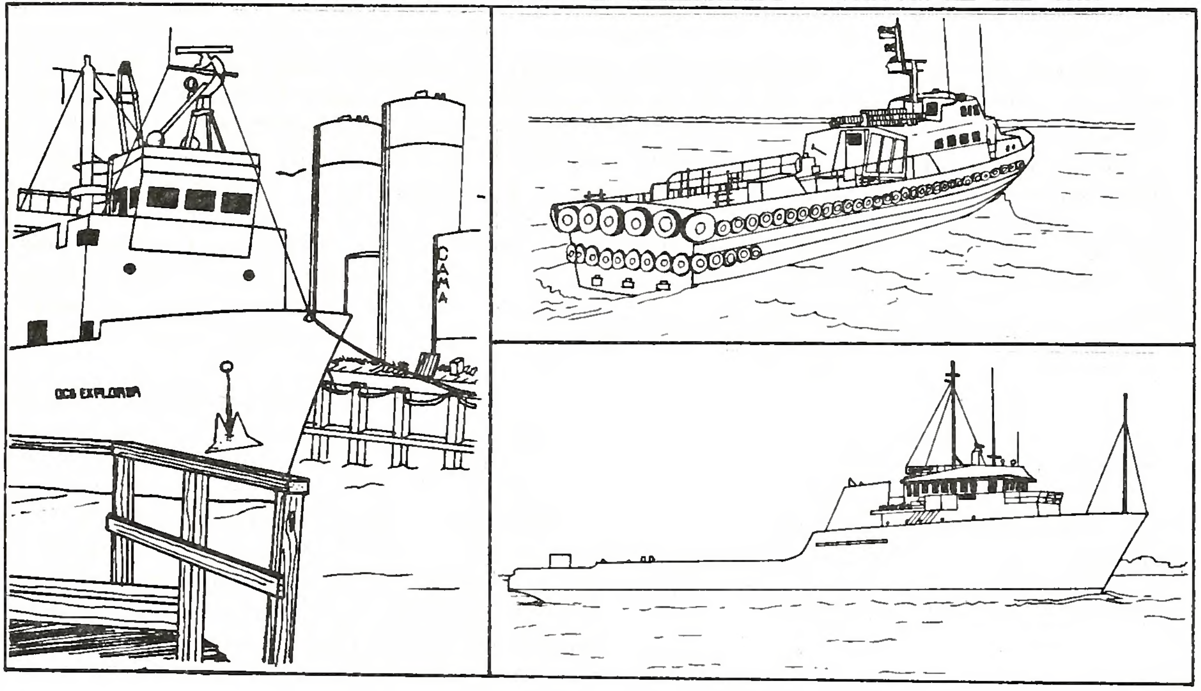
Figure 11
Temporary Service Base



Road and/or rail access is essential for a service base; large quantities of drilling mud, cement, pipes, fuel, and other materials must be brought into the base for transportation to the rig. Deliveries of fuel, mud, cement, and other supplies to the service base may also be made by boat. However, most boats using the base will be those which transport materials and workers between the base and the offshore rigs (Figure 12). Two or three supply boats and one crew boat are needed to service each drilling rig.

Bad weather or long distances may necessitate the use of helicopters for crew transport. Helicopters are often rented by the oil companies from an independent contractor found near the service base. Since helicopters arrive at and depart from the service base, refueling facilities, communications equipment, and adequate landing space must be provided there. Depending upon weather conditions, helicopters may either stay at the rigs or return to the contractor's heliport at the end of each day. A heliport may be located away from a temporary service base when the area already has an airfield significantly closer to the drilling site than the nearest site suitable for a service base, thus lowering the distance-sensitive cost of helicopter operation. Nearby airfields are also useful for bringing in new personnel for the base and maintaining contact with industry headquarters and regional offices in other cities.

Figure 12
Supply Vessels that Operate
out of a Temporary Service Base



After a temporary base is established, the company will probably expand the site into a permanent base if offshore discoveries merit increases in onshore development. The only two possible reasons for relocating the supply base are: (1) need for additional land space of waterfront, and (2) selection of a site closer to the offshore leases.

Temporary service bases are often set up under less-than-ideal conditions because of the low level of activity in the early phases of offshore exploration and the uncertainty of future development potential. The sites chosen may have inherent limitations to the expansion which might occur as offshore activity accelerates in the field development stage. The ability to expand the initial temporary site is an important concern; if the company makes a commercial resource find, it would prefer to expand a temporary base into a permanent base rather than construct a new permanent base elsewhere.

An early commitment to a service base does not necessarily commit the community to other facilities (such as oil terminals and processing plants) needed in subsequent stages of OCS development. Although the industry prefers to locate field development and production facilities together, there is little evidence that the industry now sites exploration-supporting facilities with later facilities in mind. Should large-scale production begin offshore, however, there will likely be a demand for sites for associated facilities in the vicinity of the permanent service base.

Impacts on the Local Economy

Temporary service bases involve minimal investment and provide little construction employment because of the tendency to locate in developed ports and use existing structures and facilities. Approximately 45 jobs will be created at a temporary base for each rig drilling offshore. Wharf and warehouse operations require about six persons per rig. Each helicopter requires a crew of three. Approximately six persons staff each crew-transfer boat. Ten to 12 persons staff each supply boat. About three-fourths of these jobs can be filled from the local labor force (NERBC, Factbook, p. 1.17). The average wage rate is likely to be higher than that for other waterfront employment; thus, workers may be attracted away from other industries (such as fishing).

Impacts on Natural Resources

The magnitude of environmental impacts will depend on the volume of supplies, fuel, and wastes which are stored and transferred at the service base. Since temporary service bases are not very large, they are not likely to have a significant negative impact on air quality and water quality, especially in developed ports. Environmental impacts will increase if the temporary base becomes a permanent base supporting high levels of offshore activity in the development and production stages.

Site Alteration and Construction -- The installation of a temporary service base may involve considerable site alteration or almost none at all, depending on the site chosen. In most cases, existing harbor facilities are simply modified or enlarged, involving little alteration. In other cases, service bases may be developed on land not presently used for industrial purposes. Major site alteration impacts can be expected when a previously undeveloped site is chosen. Since considerable wharfage is required by a service base, extensive dredging, pile driving, bulkheading, spoil disposal, and filling and grading may be necessary. Air and noise pollution during construction may result from the use of earth-moving equipment and other vehicles. Bedrock removal, soil leveling, and the use of pile-driving equipment may produce dust, noise, and sedimentation.

Air Emissions -- Air emission sources at a service base include evaporation from fuel storage tanks and fuel transfers, combustion from machinery and vehicles, and accidental spills and leaks.

1. Fuel Storage Tank Emissions: Diesel and other fuels are stored at a temporary service base for use by both the vessels and the drilling rigs. The volume of evaporative losses of hydrocarbons from storage tanks at a base depends on (a) tank design (roof type, diameter and capacity, paint color, and structural condition) and (b) tank location and usage patterns (diurnal changes in vapor space, emptying and filling schedule, height of vapor space, and the pressure of stored liquids).

2. Fuel Transfer Emissions: The transfer of fuel at the base from delivery vehicles to the storage tanks and from storage tanks to boats (which consume fuel as well as deliver it to offshore sites) also causes evaporative emissions. The quantity of these vapor losses depends on the temperature, density, and vapor pressure of the fuel, and how saturated the vapor space is at the time of unloading. Vapor losses from supply boat tanks can be substantial while the fuel is being transported to offshore rigs.

3. Combustion Emissions: Combustion emissions from trucks, trains, boats, and helicopters will release hydrocarbons, carbon monoxide, and nitrogen oxides into the air. Heavy machinery, such as cranes and forklifts, will also generate combustion emissions.

4. Dust Emissions: The major source of fugitive dust at the temporary service base is facilities for storing and transferring dry-pumped cement and drilling mud. Large dust clouds can form from accidental spillage or a hose blowout. This is the most visible source of air emissions at the service base.

5. Spills and Leaks: Accidental spills and similar releases of fuel and other substances will constitute a minor source of air pollution at the service base.

Water Requirements -- Each exploratory rig drilling offshore requires about 5,200,000 gallons of fresh water per year, of which 460,000 gallons must be potable (NERBC, Factbook, p. 1.14). Potable water can be supplied by desalinization devices on the rigs. Other water can be obtained from onshore sources, such as a municipal water system, and transported by supply boats to the offshore rigs.

Wastewater and Runoff -- The operation of a service base creates four sources of wastewater: sewage, bilge water, ballast water, and cooling water. Crew and supply boats generate approximately 30 gallons per capita of sewage daily (NERBC, Factbook, p. 1.38). Wastewater from such sources as galleys, sinks, showers, and laundry comes to about the same amount. Federal controls deal with sewage discharges from ocean-going vessels. Little environmental damage is expected if proper treatment and discharge procedures are followed. Bilge water, which collects in the lower portion of boats, often contains petroleum products and metallic compounds which leak from machinery. Ballast water is taken in by an empty cargo or supply boat to improve the handling of the vessel after unloading materials. Most of the ballast water used by vessels at a service base will be non-oiled. (Oiled ballast water is found mostly in oil tankers.) The composition of ballast water depends on the products transported; it is often a mixture of pollutants contained in the vessel and polluted harbor water which is added as ballast. Ballast water often has a high biological oxygen demand (BOD) and high concentrations of fecal bacteria and heavy metals. These substances can be toxic to aquatic organisms and contaminate recreational waters. Most of the ballast water used at service bases will be taken on by cargo vessels delivering materials to the base rather than crew or supply transfer boats. Only small quantities will be discharged at the base site. Cooling water, which circulates through boat engines, is either discharged into the surrounding water or is recirculated and air-cooled. Cooling water discharges are not expected to cause serious environmental impacts because of their small volume.

Small spills of stored substances will frequently occur. Drainage waters from portions of the yard where hazardous products are stored are often diked and the materials collected for treatment and off-site disposal. Any runoff which does leave the site and reach the surface or sub-surface waters will likely be industrial in nature and will contaminate the waters.

Solid Wastes -- Service bases handle two types of solid wastes: those generated by offshore oil operations and those generated by the service base itself.

Offshore wastes are more voluminous and have a greater environmental impact. During drilling operations, approximately six tons per day of solid wastes will be generated by each well. This includes drilling wastes (such as mud, mud additives, and bit cuttings); galley garbage; oily sludges; lubrication oils and waxes; rags, cloth, and packaging wastes; drums, spools, cables, and scrap metals; and human wastes. Some of this material is treated and disposed of at sea, but a large quantity is returned to the service base. Offshore operators are not permitted to dispose of any oiled drilling mud and drill bit cuttings at the platform. These wastes come in two forms: oil-based drilling mud (which is rarely used) and standard mud and cuttings which become mixed with oil during drilling. They must be returned to shore (usually in barrels) and buried. Some oil-based mud must be transported back to the mainland for centrifuging if the rig does not have centrifuging equipment on board. The discharge of non-oiled drilling mud and cuttings is permitted in federal waters. Since drilling wastes often contain hazardous materials, such as oil, acids, or heavy metals, they must be disposed of in a special landfill site where there is no danger of groundwater or surface water contamination. Less hazardous offshore wastes, such as scrap metal, paper, or wood products, are either recycled or treated at the service base before disposal in an incinerator or sanitary landfill.

Solid wastes generated by the service base itself include dunnage (material used to protect cargo) collected during unloading, garbage from supply and crew boats (approximately 6.5 pounds per person per day), and refuse from service base employees (NERBC, Factbook, p. 1.43). These wastes can be incinerated or placed in a landfill. Little adverse environmental impact will occur if these materials are disposed of in accordance with existing regulations.

Noise -- If a service base is located in a relatively quiet inhabited area, the noise which it generates may present a problem. A service base operates 24 hours a day. Sources of noise include pneumatic power tools, air compressors, pumps, compressed air machinery for painting and cleaning, industrial trucks, cranes, and auxiliary generators.

Aesthetics -- The aesthetic impact of a service base will depend largely upon the area in which it is located. The impact will be relatively minimal in an industrial port. In an undeveloped port, however, a 24-hour lighted storage facility, with heavy machinery in continual operation and trucks and boats constantly arriving and leaving, would have a significant aesthetic impact. Some type of buffer zone around the base could mitigate these impacts and might also minimize the hazards involved in fuel storage at the base.

Marine Repair and Maintenance Yards

The repair and maintenance industry presents one of the easiest ways for existing local enterprises in a frontier area to capitalize on offshore oil and gas development. Repair and maintenance firms need only augment their existing capabilities to meet the repair and maintenance needs of OCS-related vessels, rigs, and equipment. Second only to crew payroll, repair and maintenance receive the largest amount of money spent by the operators of OCS support vessels (NERBC, Factbook, p. 2.1). Fast, efficient service and highly-skilled workers are the primary needs of the offshore oil industry.

A new repair and maintenance yard catering specifically to the needs of the petroleum industry is not likely to locate in a frontier area. For the most part, these services already exist in developed ports, where many of the OCS-related facilities requiring repair and maintenance capabilities will be located. Little additional development can be expected where extensive repair and maintenance capacity already exists. Repair and maintenance services are different from other OCS-related activities in that repair operations are not unique to the oil and gas industry. Marine repair and maintenance facilities usually already exist in developed harbors to meet the demands of initial harbor users (fishing boats, cargo ships, and pleasure boats). OCS vessels will initially use existing facilities. The demand for this service by OCS-related companies will gradually increase as the offshore field is explored and developed. Repair and maintenance firms will accordingly expand staff, inventories, and work space to accommodate OCS-related vessels as well as other boats. New firms may enter the market as the demand for services increases. Although some ship equipment is unique to the oil and gas industry and may require specialized repair facilities or skills, most equipment is found on other ocean-going ships.

The repair and maintenance industry will expand in direct response to the level of offshore activity (number of rigs and number of crew and supply boats). Trips between service bases and offshore rigs will multiply with actual finds, especially if one or more rigs are put into production. The progression from exploration to development to production calls for progressively expanded repair and maintenance support onshore.

The petroleum industry uses many types of vessels in its offshore activities. These vessels may be owned by the oil companies, by support-service companies, or by independent vessel chartering companies. An oil company usually contracts for the initial fleet of boats serving a frontier area from an established boat chartering firm, frequently one of the major Gulf Coast companies. Any chartering operations already located in the frontier area would also be considered as potential contractors. The marine repair and maintenance industry is not a single firm or specific facility, but rather a range of firms that are used to keep the wide variety of OCS-related vessels and equipment in good operating condition.

These OCS boats are generally too large to be properly serviced in repair yards which cater to pleasure craft, but not large enough to require the facilities at a major shipyard. Because of the high rates and distance involved in contracting with a major shipyard, the intermediate-sized vessels used in oil and gas operations tend to seek repair and maintenance services in harbors which customarily handle larger fishing fleets. The facilities used by commercial fishermen normally have sufficient "haul out" and repair capability and charge lower rates than shipyards. Larger OCS vessels (such as drill ships, semi-submersibles, and pipe-laying barges) must be serviced at major shipyards with dry dock facilities and other necessary services.

Maintenance yards perform three types of repairs: structural, mechanical, and electronic. This work is done either at dockside or with some degree of "haul out" (by a derrick and flotation barge or a dry dock). Structural repairs maintain the vessel's superstructure and include welding, scraping, painting, and other work on the boat body and compartments. Mechanical repairs are made on the major and auxiliary drive trains, diesel engines, reduction gears, shafts, wheels, and such auxiliary mechanisms as generators, pumps, winches, and anchorage gear. Electronic repairs are made on such instrucments as radios, radar, LORAN, and fathometers.

The repair industry must be prepared to service offshore vessels and equipment whenever -- and wherever -- the need arises. Efficient service and highly-skilled labor are the primary requirements for repair and maintenance work. Around-the-clock service is required during peak OCS activity.

A repair and maintenance yard is located on the waterfront of a developed harbor, preferably near temporary and permanent OCS service bases. The equipment and layout of the yard reflect the needs of the port and can vary considerably. A large facility servicing a major port might include pipe, plate, and welding shops, storage buildings, dockside ship service facilities, and a dry dock. These facilities will be placed within the same site to allow the easy servicing of docked vessels. The majority of boat repairs can be made while the vessel is in the water. Dry docks are needed for repairs on hulls, shafts, and propellers.

Increased OCS activity during the exploration stage will not result in the major construction of repair facilities at new sites, but rather in the expansion of existing facilities. It is difficult to predict the ultimate extent to which existing maintenance firms will expand. Several factors could prompt such a decision: (1) the degree of success in oil and gas discovery, (2) the backlog of orders at current facilities, and (3) forecasts of new non-OCS business a facility could attract.

If a large number of additional OCS vessels require service, new entrepreneurs may be attracted to the port. They would not be likely to invest the capital necessary to build a dry dock or other major facilities; rather, they would purchase or rent dock space and perform specialized maintenance services. If a large oil and gas field with diversified activities and needs were predicted, a charter service owning OCS vessels might construct a new repair and maintenance facility to service its own boats.

Impacts on the Local Economy

Employment in existing yards will increase if the firms expand to serve OCS vessels. Labor requirements will range from skilled and specialized positions (such as welders, pipefitters, electricians, and machinists) to the semi-skilled and unskilled jobs of scraping hulls and other heavy labor. Some skilled positions may attract new workers from other areas, especially if those skills are not readily available in the local labor market.

Impacts on Natural Resources

The environmental impacts of repair and maintenance yards are similar to, but less severe, than the impacts of temporary and permanent service bases. Repair and maintenance yards do not have to dispose of offshore debris. Air emissions will be minimal, primarily from fuel evaporation. The construction and expansion of maintenance yards carries the same impact as temporary service bases and other waterfront facilities. The marginal impacts of construction will be less in developed harbors than in undeveloped areas. Noise and solid waste generation will vary with the size of the operation and the types of equipment used. A potential for significant impacts does exist with regard to the runoff of solvents, greases, paint residues, and other substances into the harbor. Proper runoff management practices (diking liquid storage areas, installing grease and oil traps, etc.) can minimize contaminant runoff.

General Shore Support or Ancillary Services

Independent companies contract with the offshore petroleum industry to provide a variety of specialized services, equipment, and supplies. These companies are called general shore support or ancillary services. Each company has a small labor requirement, uses small to medium-sized equipment, and is physically indistinguishable from other marine support activities on the waterfront. However, due to similar locational requirements, many of these industries are likely to cluster near ports and OCS service bases and produce local impacts comparable to a large-scale marine industry. Together, they can generate significant economic activity and increase demands on waterfront land, port facilities, and public services.

The location decisions of shore support firms are based on some threshold level of potential offshore business. If demand is less than the threshold level, which varies greatly among this diverse group of firms, a support firm will ship its products from outside the frontier region or conduct its operation from an established OCS base. For example, muds, pipe, and all other necessary materials are shipped in from established, though distant, OCS bases when a single COST well is being drilled.

As a frontier field passes through the exploratory phase and commercial quantities of petroleum are located and mined, additional support companies find it advantageous to expand or to locate adjacent to or within a service base in the frontier harbor. Petroleum companies coordinate the storage and shipment of supplies to offshore facilities. If a major new service base is constructed, many general support firms could lease space within the base. This location is the most cost-effective. In developed harbors, where the service base uses existing facilities, general shore support companies may rent commercial space near the base or may already be located near the harbor.

Some ancillary companies, such as a diving service, require a waterfront location with wharf space. Other companies, such as a rental tool company or a helicopter contractor, can locate anywhere they have good access to the waterfront and service base. Locational flexibility is also tied to the bulk of items supplied to the offshore industry. A company shipping large volumes, such as the mud supplier, will locate adjacent to the harbor, with access to rail, highway, and water transportation. Companies responsible for small volumes, such as a catering service, can locate in the general vicinity of the harbor. Other factors, including startup and operating costs, will have a major influence on the site selections of ancillary firms.

General shore support companies fall into one of two categories: (1) companies which provide services and equipment directly related to oil and gas development, and (2) companies which service several industries and could expand their operations to service the oil and gas industry.

1. Businesses directly related to oil and gas development: This group of ancillary industries includes drilling mud companies, cement companies, drilling tools and equipment companies, wellhead equipment companies, well logging and perforating companies, oil spill recovery services, helicopter companies, catering companies, diving companies, and inspection and testing services. Because these firms specialize in servicing and providing equipment and supplies to the oil and gas industry, it is unlikely that they will already exist in a frontier region. During the exploration phase, oil companies are apt to contract with established support firms in other regions. These companies might expand to service the frontier region or establish small operations in frontier ports if OCS development in the frontier region reaches the production stage.

2. Businesses related to several industries: This group of ancillary industries includes trucking and stocking companies, machine shops, welding companies, labor contractors, office suppliers, crane and lift operators, fuel and lubricant suppliers, and communication equipment suppliers. Supplies, equipment, and services for the offshore oil and gas industry are only part of the overall activity of these firms. The presence of the oil and gas industry in a frontier region serviced by these companies opens a new market for their products and services. These firms will adjust their business practices and expand operations by identifying and pursuing opportunities that are available with the offshore industry. Offshore operators seek reliable, responsive, 24-hour service and a willingness to expand production lines to meet offshore demands. While many firms can provide supplies and services to the oil industry, those firms that invest time and energy to learn about the offshore industry are likely to receive the bulk of oil-related business.

Up to 30 days prior to a lease sale in a frontier region, mud and cement companies will lease appropriate land and facilities in the area, anticipating an immediate demand for drilling supplies when exploration begins (NERBC, Factbook, p. 10.11). Temporary facilities will also be leased by drilling tool companies that supply drilling operators with bits and other necessary equipment. Wellhead equipment companies may set up small bases as centers of operation for technicians supervising wellhead installations.

As exploration commences and rigs move into the region, helicopter firms will establish temporary bases from which crews and light supplies can be flown to the rigs. A caterer will be contracted by the drilling operator to provide food and housekeeping services for rig crews. The caterer may contract with a local food supplier to deliver the goods directly to the service base, eliminating the need for a new catering facility. A diving company may also be contracted for repair work on a standby basis. It may set up a small onshore facility as a center for coordinating operations.

As exploratory wells are drilled, specialized rental tools used "downhole" will be required for well servicing and repairs. These tools will initially be shipped from existing OCS production regions (such as the Gulf Coast) to the service base for direct transport to offshore rigs. Well logging and perforating services, used to evaluate geological formations being drilled, will also be contracted by the drilling operator. Well logging companies may open a small facility in the region if exploration activity is sufficiently high. Local companies that offer marine supplies and services may be asked to stock specialized parts. Local welders, fabricators, and machine shop operators may be given various oil industry contracts. Drilling operators may begin to hire local contract labor for both onshore and offshore jobs.

Offshore activity will intensify as commercial finds are made and the field development stage begins, significantly increasing the activity of onshore ancillary industries. If not already in existence, permanent facilities will definitely be established in the frontier area by ancillary firms that specialize in supplying the offshore industry. Those firms which service several industries are likely to increase their levels of operation and may expand their present facilities. Trucking and stocking firms will begin delivering and storing drill pipe, casing, tubing, and other drilling supplies. Completion and production services, used to prepare a well for production, are likely to set up facilities in the frontier region. As development commences, oil spill control companies may be contracted on a stand-by basis to provide immediate service for spills that might occur either at the platform or while oil is transported to shore. Diving services will expand to include pipeline and platform construction work. Inspection and testing companies will be hired to examine pipelines and platforms for structural integrity and are likely to set up small facilities for equipment storage, repair, and general administration. The demand for fabricators, welders, machine shop operators, and contract labor will also increase during the field development stage.

Impacts on the Local Economy

The cumulative employment and environmental impacts of ancillary industries will be small during the exploration stage and increase with the level of offshore activity as the oil and gas industry moves into the field development and production stages (when and if commercial quantities of oil and gas are discovered). Due to the varied nature of ancillary industries, it is difficult to say when they will expand existing operations or move into a frontier community. If these companies move into an area gradually, they will have less impact than most other facilities associated with OCS development. Major impacts could occur if a large number of ancillary firms establish new facilities in a small area within a limited timespan.

Employment data for major types of shore support companies is presented in Table 1. Employment in each firm includes specialized skills, general labor, and administrative staff. Each company will provide a few local employment opportunities, normally in general labor, but companies moving to a frontier area will bring at least some staff from established facilities elsewhere. If all potential firms moved into a single community, the effect on local employment and commercial space would be significant.

Table 1
Major OCS Support Companies
and their Average Employment

Company	Average Employment
Mud Supplier (drilling mud)	13
Wireline Company (for drilling)	15
Gas Lift Company	5
Logging and Perforating Company (testing)	10
Welding Shop	23
Rental Tool Company	10
Fishing Tool Company	9
Wellhead Equipment Company	12
Machine Shop	9
Trucking Firm	15
Cementing Company (cement for drilling)	12
Supply Store	9
Downhole Equipment Company	11
Other (includes onshore catering support)	96
Total Employment	260

SOURCE: Clark et al., Recovery Technology, p. 145.

Impacts on Natural Resources

Onshore support firms tend to use existing commercial space and facilities. With the possible exception of the mud supplier, installation and construction activities for individual firms are insignificant, especially in a developed port city (Clark et al., Recovery Technology, p. 145). Collectively, however, they may have an effect on a single harbor. If a new temporary or permanent service base is constructed in a frontier area, many ancillary service companies are likely to lease space within the service base. Most of these firms have limited investment capital and prefer to conduct their operations in leased facilities. This strategy reflects the lifespan of an oil field and the specialized nature of most support services within each phase of OCS activity. Air quality, water quality, and noise impacts will depend on the individual ancillary activity. For example, mud and cement firms may create minor problems with fugitive dust. The impact of most ancillary activities will be minimal and similar to small industrial and commercial operations throughout the community.

FEDERAL ACTIVITIES AND THE FLOW OF INFORMATION DURING EXPLORATION

Drilling during the exploration stage occurs on the outer continental shelf in areas of federal jurisdiction. Management responsibility is delegated to the Department of the Interior by the OCS Lands Act. The U.S. Geological Survey (USGS) oversees exploratory drilling activities. Permits must also be issued by both the U.S. Coast Guard and the Army Corps of Engineers before any drilling can begin. Federal, state, and local roles in the exploratory stage activities are detailed below.

Federal Role

After a lease sale on the outer continental shelf, the USGS may issue permits under Section 11 of the OCS Lands Act for geophysical and geological exploration activities. The permit is issued by the Area Oil and Gas Supervisor, USGS, under regulations found in Volume 30 of the Code of Federal Regulations, Section 251.

The lessee must submit a plan to the Area Oil and Gas Supervisor of the USGS which becomes the basis for specific permits. This plan must include: (1) a description of drilling vessels, platforms, or other structures showing their location, design, and major features, including features pertaining to pollution prevention and control; (2) the general location of each well, including surface and projected bottom hole location for directionally drilled wells; (3) structural interpretations based on available geological and geophysical data; and (4) such other pertinent data as the supervisor may prescribe.

In reviewing these plans, USGS has relied on the environmental impact evaluation prepared by the Bureau of Land Management (BLM) and the U.S. Fish and Wildlife Service (FWS) prior to leasing. Many of the suggested conditions or hazards are already accounted for in lease stipulations developed by BLM, FWS, and USGS, under Secretarial Order 2974. To supplement these conditions, the Area Oil and Gas Supervisor may issue operating orders that govern exploration, drilling, and production in leased areas.

State Role

Although participation in the exploration decision making can often be the most significant opportunity states have to shape OCS-related onshore activities, many states and local governmental agencies neglect maximum involvement at this point. They consider the exploration stage's relatively short timespan, limited job opportunities, and minor onshore facilities, and often move on to greater planning challenges. Many states and localities, however, tend to underestimate the speed of the oil industry's transition from exploration to field development decisions. In Britain's North Sea experience, the interval between the discovery of a commercial field and development drilling has averaged three to five years. The Department of the Interior estimates a 40 to 47 month interval between a commercial discovery and the start of development drilling in U.S. "frontier" areas. The oil industry must make very quick decisions about field development, transportation, onshore processing, and petroleum marketing in order to obtain equipment and construct new facilities. A marketable discovery requires the application of sophisticated engineering techniques, and contracts for oil and/or gas field development may be drawn up within twelve to eighteen months. It is, therefore, important for both local and state officials and planners to participate fully in the decisions to be made during this exploration phase.

The 1976 Amendments to the Coastal Zone Management Act added a provision that brings states into this process insofar as exploration brings associated coastal zone impacts. Section 307(c)(3)(B) of the Act requires that any "plan for the exploration or development of . . . any area which has been leased under the Outer Continental Shelf Lands Act . . . shall attach to such plan a certification that each activity which is described in detail in such plan complies with such State's approved management program . . . ." State responsibilities during the exploration stage include: (1) review and comment on plans and permits, (2) consistency certificate determination for plans covered in approved Coastal Zone Management programs, (3) consultation with federal, local, and industry officials, and (4) the preparation of economic and facility siting plans. The documents handled by the state in its review and comment and information exchange activities cover a range of topics from air and water discharges to transportation management to planning for new local economic development. In addition, the governor's office serves as the link between units of local government and the Secretary of the Interior on OCS matters [P.L. 95-372, Section 19].

In addition to its intervention during various steps in the permit process, the state serves an important planning and coordinative role during the exploration and field development stages:

> The Outer Continental Shelf Lands Act Amendments of 1978 (Public Law 95-372) . . . give states a new pivotal role in the entire OCS leasing and permitting process. Section 19 of the Act was designed to ensure that governors of the affected states and local government executives within such states should play a leading part in OCS decisions, particularly those relating to lease sales and exploration, development and production plans. The section provides the mechanism for involvement of governors and local government officials. In relation to Exploration Plans it allows local governments to submit recommendations to the Secretary,

> but only through the governor's office. The state's position is therefore that of primary actor in the OCS leasing and permitting process, with mandated lines of communication to industry and local government as well as to the Secretary of Interior and the federal regulatory agencies. This gives the state a unique vantage point to develop planning strategies and to assume a positive role in the exploration decision process, and provides the means to bring state policies to bear on the Exploration Plan decision.
> (NERBC, Strategies for State Participation in OCS Exploration Decisions, p. 85).

A state should get involved in the OCS decision-making process as early as possible and not wait for the formal consultations that occur when the many exploration documents are submitted. If prior contact is not made, the state may find that the formal proposal submitted by an oil company ignores or provides insufficient documentation for state concerns such as environmental protection, natural resources management, and economic development. The state's early involvement, while an industry's plans for exploration are still flexible, may allow the technical aspects of the plan to be influenced by state concerns.

Local Role

Local governmental officials and planners are given a legislative sanction under the OCS Lands Act Amendments to play a leading role in the OCS decision-making process. This role begins with the establishment or strengthening of the lines of communication between the local agencies (and interested parties) and the agencies chosen by the state to handle the different requirements of the OCS development process. Although this state-local coordination should be a joint responsibility, the local agencies must often demonstrate their interest and desire for involvement in the OCS-related activities before they are taken seriously by the state. After the lease sale, it is important for local concerns to be voiced prior to the oil companies' initiation of the permit process. This will allow the state to consider local problems in the development of sound state planning strategies to deal with the exploration stage and its related permit process. No matter how far-sighted and comprehensive a state's planning strategy, the facility-siting portion of it can be implemented only through the application of local zoning ordinances and other development guidance tools. If local policies and plans are not taken into account in the state's formulation of an OCS plan, the entire exercise could be wasted and the opportunities for securing the benefits and mitigating the adverse impacts of OCS-related onshore developments could be lost.

State agencies (such as the N.C. Department of Natural Resources and Community Development) often develop direct lines of communication and close working relationships with coastal communities and are able to reflect local interests in their reviews of the Exploration Plan, Environmental Assessment, and other oil company submittal documents during the permit process. Since it is the state's responsibility to pass along local government's comments to the Secretary of the Interior, the localities should press to have their requirements for protection from the adverse impacts of OCS activities included in the state's OCS planning program, especially if those concerns are not completely reflected in prior state agency reviews. The determination of these local requirements and the establishment of reliable OCS contacts in state agencies are critical steps for local planners and governments to pursue in order to protect their interests and become active players in the game of OCS development.

The flow of information from the state to the local entities during the permit process should follow an agreed upon set of systematic procedures for everyone's maximum benefit. Local governments may participate in the permit process by intervening and submitting recommendations to the state at certain points. Planners and government officials must be well aware of these critical intervention points since all local comments must go directly to the state, and the state's own comments and appeals must often be forwarded to the USGS or other federal agencies within a very short time period (usually within two to four weeks). If local governments are to evaluate any oil company applications, they must receive immediate notice of an application from the state and act quickly in relaying their comments for the state's timely consideration. The critical points for local review and action during the exploration stage include the lessee's submission of the Exploration Plan and Environmental Report, the USGS' production of an Environmental Assessment (often with the state's help), and the oil and/or gas company's applications for a Consistency Certificate and a NPDES Permit.

Exploration Plans

The Exploration Plan, which is prepared by the oil company, contains the proposed type, sequence, and timetable of offshore exploration activities; a description of drilling vessels, platforms and other geophysical equipment to be used; an oil spill containment and cleanup plan; approximate locations of proposed exploratory wells; current structure maps and schematic cross sections; a statement regarding the general nature of information deleted from the Freedom of Information (FOI) Act; and other relevant data.

The oil company's (lessee's) Exploration Plan is submitted to the USGS, and when deemed complete, a copy of the EP, omitting the FOI Act-exempt portions, is forwarded to the governor and to the state coastal zone management agency (the N.C. Office of Coastal Management). Since the USGS Director or the Area Oil and Gas Supervisor must issue a decision on the Exploration Plan within 30 days of its submittal, the state will generally have ten to 15 days to review and comment. The Director must consider the written comments submitted by the state in the evaluation of and final decision on the plan. A state that is adversely affected by an exploration plan decision can appeal to the Director and/or to the Secretary of the Interior within 30 days with written statements supporting the decision's reversal or modification.

Environmental Reports (Exploration)

The Environmental Report (ER), prepared by the lessee, supplements the information contained in the Exploration Plan and helps in the assessment of impacts from exploration activities. While the regulations specify that the ER and the Exploration Plan are two separate documents (primarily because the ER is not subject to "approval" or "disapproval" beyond the determination of its completeness), the ER is submitted and accompanies the plan through all review processes.

The USGS Director forwards the Environmental Report to the governor and the state's coastal zone management agency; the state has the same amount of time for review and comment (ten to 15 days) as with the Exploration Plan. The USGS Director must again consider all written comments from the state before rendering a final decision on the ER.

The Environmental Report contains:

a) a brief description (if not included in the Exploration Plan) of

   1. an oil spill contingency plan for exploration activities
   2. land requirements of onshore facilities
   3. the number and geographical origins of employees
   4. most likely travel routes for boat and aircraft traffic between offshore and onshore facilities and the estimated frequency of travel
   5. the quantity and composition of solid and liquid wastes and pollutants to be generated
   6. the major supplies, services, energy, water, or other resources within affected states required for exploration, and
   7. environmentally sensitive or potentially hazardous areas including site specific geologic characteristics, physical oceanography, onsite floral and fauna, uses of area under exploration (i.e., fishing, military), and archeological and cultural resources

b) an assessment of direct impacts on offshore and onshore environments expected to occur as a result of exploration, with special emphasis on unavoidable and irreversible impacts

c) air quality information for projected OCS facilities

d) other information required by the Director

e) a contact person for inquiries by the Director and the state

Environmental Assessments

An Environmental Assessment is prepared for each Exploration Plan to evaluate the likely impacts of the proposed activities and to determine if approval of the plan would constitute a major federal action significantly affecting the quality of the human environment and thus requiring the preparation of an Environmental Impact Statement. The EA is prepared by the USGS Area Supervisor/Deputy Conservation Manager within 30 days after the Exploration Plan is submitted and deemed complete.

In addition to the proposed exploration activities and their environmental consequences, the Environmental Assessment contains a section regarding controversial issues and opposing viewpoints. The state's comments on the related Exploration Plan and Environmental Report are considered in the preparation of an EA if submitted early in the review process. States may be consulted and are often asked to provide assistance during the preparation of the Environmental Assessment.

Consistency Certification

A state which expects OCS activities to affect its coastal zone must include a reference to OCS plans in its Coastal Zone Management Program list required by the Federal License and Permit Regulations (authorized by the Coastal Zone Management Act of 1972, as amended, and 15 CFR 930-D). This list of license and permit activities which may reasonably be expected to have an effect on the coastal zone must be provided to the Department of the Interior which will in turn, make the information available to OCS oil and gas lessees and operators.

When the lessee is satisfied that the proposed activities meet federal consistency requirements and that they comply with the state's coastal zone management program, it will submit the consistency certificate to the USGS Director along with the Exploration Plan. State review begins on the date the state receives the lessee's Exploration Plan, consistency certificate, and other supporting information from the USGS Director. The state must ensure timely public notice and may hold public hearings. State concurrence will be presumed if a determination is not made within three months, either concurring or objecting, unless the state requests an additional three-month extension for review and gives its reasons for the delay. If the state has not made a determination after six months, its concurrence will be conclusively presumed.

Consistency certification must take the form of a declaration by the lessee or the operator that:

> The proposed activities described in detail in this plan comply with (name of state) approved coastal management program and will be conducted in a manner consistent with such program.

The certification must be supported by the same information which accompanies the Exploration Plan (excluding proprietary information) and the Environmental Report. It must include a brief assessment of the probable coastal zone effects and a brief set of findings indicating that the proposed activities, their associated facilities, and their combined effects are all consistent with the provisions of the coastal zone management program.

If the state objects to the consistency certification, it must give reasons and supporting information concerning each activity it finds to be inconsistent with its coastal zone management program. On receipt of a state objection, federal agencies may not issue any license or permit until the objection is resolved either through modification of the proposed activities or through an appeal to the Secretary of Commerce.

Once state concurrence is issued or conclusively presumed for an OCS Plan, the oil company is not required to submit additional certifications when federal applications are filed for each of the activities described in the Plan (e.g. Permit to Drill). The company must, however, supply the state with copies of permit applications to allow monitoring of approved OCS activities.

Federal regulations encourage applicants to consolidate related permit and license activities and submit a single package for state review. In the case of exploration activities, this would involve the submission of one consistency certificate for the Exploration Plan, Corps of Engineers Section 10 Permit, and EPA NPDES Permit. An objection by the state to part of the package would not prevent the applicant from receiving federal agency approval for other activities in the package which are found to be consistent with the state's coastal zone management program.

Corps of Engineers Section 10 Permits (Department of the Army Permit to Perform Work in or Affecting Navigable Waters of the United States)

Department of the Army permits are administered by the Corps of Engineers. Application is made to the District Engineer, who carries out the consultation procedures and coordinates the responses. The oil company (lessee) must file an application to construct and operate structures required for exploration operations. The Corps, required to coordinate its review with other agencies and the public, issues a Public Notice within fifteen days of receiving the permit application and circulates it to a wide audience (including mayors' offices, environmental groups, local newspapers, state environmental agencies, and maritime exchanges. The Public Notice generally includes:

- The name and address of the applicant and the location and description of the proposed activity

- A plan and elevation showing site location and character of activities including size relationship of the proposed structures to the size of the affected waterway and depth of water in the area

- A list of other government authorizations obtained or requested

- A statement concerning a preliminary determination of the need for and/or availability of an environmental impact statement, and

- Any other available information which may help in evaluating the proposal.

The state will then have between 15 and 30 days from the date that the notice was mailed to submit comments to the Corps of Engineers. All comments received in response to the Notice will be considered by the Corp's District Engineer in deciding all subsequent actions on the permit application (i.e., if a public meeting or public hearing should be held and if other federal agencies should be consulted). A state with an approved CZM program and which has included COE permits in its program lists will receive the lessee's consistency certificate.

When the structures of the OCS are to be constructed on lands which are under mineral lease from the Bureau of Land Management, the BLM, in cooperation with other federal agencies, is presumed to have fully evaluated the potential effects of the leasing program on the total environment. The Corps of Engineers will, therefore, limit its evaluation of the proposal to its impact on navigation and national security. If state concerns and objections go beyond questions of navigation and national security, the COE will forward the matter to the Department of the Interior.

NPDES Permits

The oil company (lessee) must submit its permit application to the Environmental Protection Agency (EPA) 180 days before any intended discharge. EPA issues a public notice on the application's proposed issuance, denial, or modification with copies forwarded to the state and other interested parties.

The public notice should briefly describe the company's proposed activities and their expected discharges, including cooling water, treated sewage, mud effluent, waste cement, seawater distillates, washwater and cuttings, and mud and cement discharged at the ocean floor.

Written comments or requests for a public hearing from the state and general public concerning the EPA's tentative determination on the application may be submitted up to 30 days after the notice is issued. A state's water pollution control agency may request either (1) a public hearing on the permit application or (2) an adjudicatory hearing on issues of fact or a legal decision on issues of law regarding the EPA Regional Administrator's determination of an application. If the state has an approved CZM program and has included NPDES permits in its program lists, it will receive the oil company's consistency certificate. If the application is deemed inconsistent with its CZM program, the state can object to the permit's issuance and appeal to EPA's Regional Administrator.

OCS Air Quality Regulations

The OCS Lands Act Amendments require that the Secretary of the Interior establish a regulatory program (consisting of exemptions, significance levels, and controls) to ensure that OCS activities do not jeopardize the attainment or maintenance of national ambient air quality standards. The Department is authorized to regulate air emissions from OCS activities only if those emissions significantly affect the air quality of any state.

After the Department of the Interior determines that emissions will significantly affect onshore air quality, it specifies the types of controls required to help minimize those impacts. It is then up to the oil company to propose the necessary control technology and submit the information with the company's Environmental Report. In approving the related Exploration Plan, the USGS Director also approves the oil company's choice of technology. The state may participate in the air quality regulatory program in several ways. In reviewing the oil company's Exploration Plan and accompanying Environmental Report, it may also review and comment upon air emissions data and the company's proposed technology. A state with an approved CZM program that cites air quality standards may also consider onshore air quality impacts as part of its consistency certificate determinations. If the state determines and offers evidence that emissions from an exempt OCS facility will significantly affect the air quality onshore, then the USGS Director may require the oil company to submit additional information to determine if control measures are needed.

Oil Spill Prevention, Control, and Cleanup

The prevention of oil pollution resulting from OCS exploration activities is regulated by the USGS, which issues operating orders outlining requirements for drilling procedures, blowout prevention equipment, and other related standards. A plan detailing the procedures, personnel, and equipment to be used for the prevention, reporting, and cleanup of spills of oil or waste materials during exploration activities must be submitted by the operator to USGS as part of the ER. The plan must include information on response time, capacity, and location of equipment. The Coast Guard, EPA, and USGS are currently developing a Memorandum of Understanding outlining the provisions for Coast Guard review of the lessee's oil spill contingency plan.

In addition to the activity-related plans required by USGS, the EPA, under the terms of the Federal Water Pollution Control Act of 1972, requires the preparation of Spill Prevention, Control and Countermeasure Plans (SPCC Plans) for certain oil storage facilities. The regulations for the SPCC Plans apply to above-ground storage facilities with capacities greater than or equal to 1,320 gallons and to below-ground storage facilities with capacities greater than or equal to 42,000 gallons. An SPCC Plan must be certified by a registered engineer and implemented by the owner/operator of the facility. SPCC Plans are not submitted to EPA unless a spill of more than 1,000 gallons occurs or two spills of any size occur within a one-year period. If a spill or a blowout does occur on the OCS rig or structure, control and cleanup is the responsibility of the affected company in accordance with its previously approved contingency plan. Control measures performed at the well site and within 500 meters of the site will be monitored by the USGS. The measures taken to clean up and mitigate the effects of the spill outside that radius will be monitored by a federal On-Scene Coordinator (OSC) assigned by the Coast Guard. The Regional Response Team (RRT) (Coastal), representing federal, state, and local organizations and chaired by the Coast Guard, will be available to the On-Scene Coordinator (OSC) for advice and guidance. Local and regional contingency plans developed by the OCS, RRT, and offshore operators will also be used if there is a need.

Applications for Permits to Drill

The oil company submits its application for a drilling permit to the USGS Area Oil and Gas Supervisor, who reviews it and transmits a copy of the application to each affected state. The application must include:

- the well's surface location
- the projected bottom hole location
- water depth
- proposed blowout prevention and casing program and any other required data.

The permit to drill must conform to the applicable approved Exploration Plan and is not subject to a separate state consistency review under the Coastal Zone Management Act. Affected states are only notified of the application; their comments are not invited at this late stage. The USGS generally reviews the application within 4 to 6 weeks and, if approved, the USGS Supervisor notifies all affected states of the final decision.

OCS Oil and Gas Information Program

The USGS's OCS Oil and Gas Information Program requires lessees to provide the agency with access to information from offshore exploration activities. The USGS uses this information to prepare two documents, a Summary Report and an Index, which it submits to state agencies and, upon request, to local governments. The documents are to aid local and state agencies in planning for the onshore impacts of offshore activities and in reviewing exploration plans and other documents.

The Summary Report is designed to be an "information bridge" between the federally-managed OCS development process and the state and local planning process. USGS seeks to satisfy two objectives in the production of Summary Reports:

a) assisting the states in planning for onshore facilities and impacts resulting from offshore activities, and

b) providing states with timely summary information so that state and local planning processes do not lag behind continuing OCS exploration, production and development activities.

In order to meet the objectives stated above, USGS plans to link the production of Summary Reports to significant OCS events. For example, a report will be issued shortly after a lease sale to aid states in their review of Exploration Plans or in making consistency determinations. Other significant events would include initial commercial discoveries and the submission of Development and Production Plans for review. Reports will probably by updated semi-annually and may be in the form of a "Status Report" if no significant events take place. The initial Summary Report for the South Atlantic region was issued in July 1980, and its related update was released in February 1981 (See Appendix A).

The contents of the Summary Report may include:

- estimates of oil and gas reserves and resources and, when available, projected rates and volumes of oil and gas to be produced from leased areas

- magnitude and timing of offshore activities

- methods of transportation to be used and approximate routes to be followed

- general location and nature of near-shore and onshore facilities expected to be utilized .

The Summary Report is intended to provide information to aid states in making decisions with regard to other documents. The states are consulted by the USGS Director as to the nature, scope, timing, and content of the Summary Report.

Federal regulations require that the USGS Director and the Director of the Bureau of Land Management prepare an index listing all relevant actual or proposed programs, plans, reports, Environmental Impact Statements, lease sale information, and any similar type of relevant information. This Index is prepared in four volumes for the four OCS regions: Alaska, Atlantic, Gulf of

Mexico, and Pacific. (The Atlantic Index is listed in Appendix A.) The Index is sent to the affected states, and upon request, to any affected local government. Affected states may request copies of the documents listed in the Index unless they are considered confidential under the Freedom of Information Act.

The Index, which may be prepared annually if warranted by OCS activities, consists of separate sections for each document produced in the OCS decision-making process. Each section contains a description of the document, a schematic showing its timing in the OCS process, and a listing of all such documents prepared by lease sale number. The format is designed to allow the user to compare all documents of one type or to trace a single lease sale area through all stages of the OCS process.

Regional Transportation Studies Plan

The Intergovernmental Planning Program (IPP) for the Leasing and Transportation of OCS Oil and Gas is directed by the Bureau of Land Management (BLM) to provide a forum for early and continuous coordination and consultation among parties having substantial interests in OCS transportation decisions, especially federal, state, and local government agencies and the petroleum industry. The program is intended to be conducted at a level which is sufficiently technical to provide informed guidance for federal and state decision makers. The major program product at the exploration stage will be the Regional Transportation Studies Plan.

Regional Transportation Studies Plans for tracts off the North Carolina coast will be prepared by the South Atlantic Regional Technical Working Group (RTWG), which is composed of federal and state officials, industry representatives, and other interested parties. This phase of the Intergovernmental Planning Program will begin at the time of a lease sale decision and should be completed by the time of marketable discoveries. Probably transportation corridors will be refined using post-sale information, and the Regional Transportation Studies Plan will be produced. The studies included in the plan will analyze the technical feasibility of various transportation modes and mixes in a particular region and augment the regional data base so that site specific studies for transportation facilities can be implemented as soon as commercial quantities of petroleum are discovered. Design of the Site-Specific Transportation Studies Plan may also begin in this phase.

States participate in the production of the Regional Transportation Studies Plan through membership in the regional technical working groups. Through the Regional Transportation Studies Plan, the working groups make recommendations to BLM on studies that might be carried out by BLM and other federal or state agencies.

After the oil company has submitted all of the required documents, met the review criteria and is issued a permit to drill, the exploration process can begin in earnest. Any data regarding oil and gas resources or subsurface geology obtained from exploratory drilling is proprietary information owned by individual oil and/or gas companies. As such, this data is not released to the general public, except upon the request of the company. Although it still remains proprietary, a copy of the findings is given to the USGS in compliance with federal regulations.

In cases where a COST hole has been drilled in a frontier area by a consortium of companies, information can be released to the public either (1) after five years from the drilling date, or (2) within 60 days after a lease-sale is held within 50 miles of the drilling site. Within these specified time periods, oil and gas companies have exclusive rights to the information obtained during exploratory drilling, without obligation to make the data public. The USGS can purchase the information from the companies.

Each company or group must obtain, analyze, and make judgmental decisions on its own data with the hope that its assessments and predictions of the location of oil and gas reserves are more accurate than its competitors. The results and findings from exploratory drilling will lead to field size determination and to possible production drilling.

The Field Development Stage

Exploratory drilling provides the oil and gas industry with information on hydrocarbon-bearing formations, such as well pressures, the thickness and extent of hydrocarbon traps, and other indicators of the amount of oil and gas in an offshore field. If exploratory drilling reveals commercial quantities of oil and gas, a company will balance its resource estimates, cost calculations, and market assessments to determine the timing and level of field development. Company strategies are refined and reoriented toward production as new and more detailed information comes forth; companies order production platforms, set up onshore support facilities, and commence drilling and pipeline installation. The pattern of onshore and offshore development crystallizes during the field development stage and is unlikely to change throughout the productive life of the field. The field development stage begins about four years after the lease sale and lasts for five yars or more.

If exploration reveals sufficient quantities of oil and gas, oil companies will formulate development plans and transportation plans (choosing to bring oil and gas to shore by tanker, pipeline, or both). Department of the Interior regulations require the companies to submit development and production plans and environmental reports to the federal government. Companies must also apply to the federal government for drilling permits, pipeline permits, and other permits to protect navigation and environmental quality. Affected state and local governments may review and comment on these documents. Development and production plans and environmental reports may be supplemented by a development phase environmental impact statement from the Department of the Interior. Environmental impact statements during the exploration stage deal with a range of oil and gas estimates that could be discovered, since no one knows exactly how much oil and gas exists until exploratory drilling occurs. Development stage impact statements work with the more accurate resource estimates which exploration generates. Development stage impact statements and the industry's development plans and environmental reports give coastal communities a more realistic assessment of the level of activity and impacts they can expect from onshore and offshore development.

Local and state government responsibilities during the field development stage focus on the location and character of onshore facilities, managing their environmental and employment impacts, and providing public services to new industrial facilities and their workers. The offshore oil and gas industry draws most heavily on coastal communities during the field development stage. An onshore construction "boom" may create temporary high levels of employment which will taper off significantly once offshore production begins and onshore facilities are operating. Essentially all major facilities for the production stage are installed by oil companies, gas companies, and their contractors during the field development stage. These facilities may include:

permanent service bases, repair and maintenance yards, general shore support services, platform fabrication yards, pipelines, pipe coating yards, platform and pipeline installation bases, partial processing facilities, gas processing and treatment plants, marine oil terminals, and refineries. Some of these facilities will locate in existing harbor facilities while some will be constructed from scratch.

A large oil or gas find located far from existing harbor facilities or oil and gas production facilities will create the greatest onshore development "boom." A region with developed harbors will have fewer problems assimilating OCS-related development, especially if offshore discoveries are small or moderate. Onshore development impacts and the factors influencing onshore development decisions are discussed below for each field development activity and facility.

FIELD DEVELOPMENT ACTIVITIES AND THEIR ONSHORE IMPACTS

Development Drilling

Exploratory drilling provides the oil and gas industry with information on hydrocarbon-bearing formations, such as well pressures, the thickness and extent of structural traps, and other indicators of the amount of oil and gas in an offshore field. If exploratory drilling reveals commercial quantities of oil and gas, a company will balance its resource estimates, cost calculations, and market assessments to determine the timing and level of development drilling. Production platforms are ordered when these indicators justify resource extraction.

Development drilling creates the wells which convey oil and gas from the reservoir to the surface during the production stage. Whereas exploratory drilling uses temporary platforms, which are readily moved from one location to another, development drilling employs fixed platforms which are attached to the sea floor for the productive life of the field. Production platforms are used to drill wells, extract oil and gas, and house offshore personnel, materials, and equipment. They are constructed onshore at platform fabrication yards and are then towed to the offshore tract and fixed to the sea floor. Platforms used in the United States typically support a crew and operations for periods of a week or more to minimize transportation costs. Materials are delivered to the platform by boats. Drilling crews are typically transported by helicopter.

Platforms are designed and constructed to meet the specific requirements and conditions of the production site. Production platforms are not standardized; while such components as derricks, cranes, motors, and housing modules are standard and interchangeable, the structure they rest on may have to stand in water ranging from fifty to one thousand feet deep. Platform design must also consider sea floor stability, the weight of the structure, winds, storm waves, and the number of wells to be drilled from the platform.

There are two major types of production platforms: fixed pile platforms and gravity platforms. All platforms consist of a deck and a jacket. The deck assembly contains modular units that can be changed for each operation conducted from a platform: development drilling, oil or gas recovery, and well maintenance and "workover." Those units include derricks, drilling equipment, crew quarters, production equipment, helicopter pads, and materials storage areas. The jacket is the large skeletal framework which supports one or more decks and is attached to the sea floor.

The steel fixed-pile platform, developed in the Gulf of Mexico, is the most common platform in the United States. It consists of the traditional steel jacket (a truss framework of tubular steel) which usually comes to mind in discussions of offshore production (Figure 13). The platform is constructed in two sections onshore. The jacket is floated to the drill site (Figure 14) and secured to the sea floor by piles driven through legs. The deck sections are floated to the site and lifted atop the jacket by a derrick barge. Steel fixed-pile platforms are currently being used in water depths of over 500 feet.

Figure 13
Steel Fixed-Pile Platform

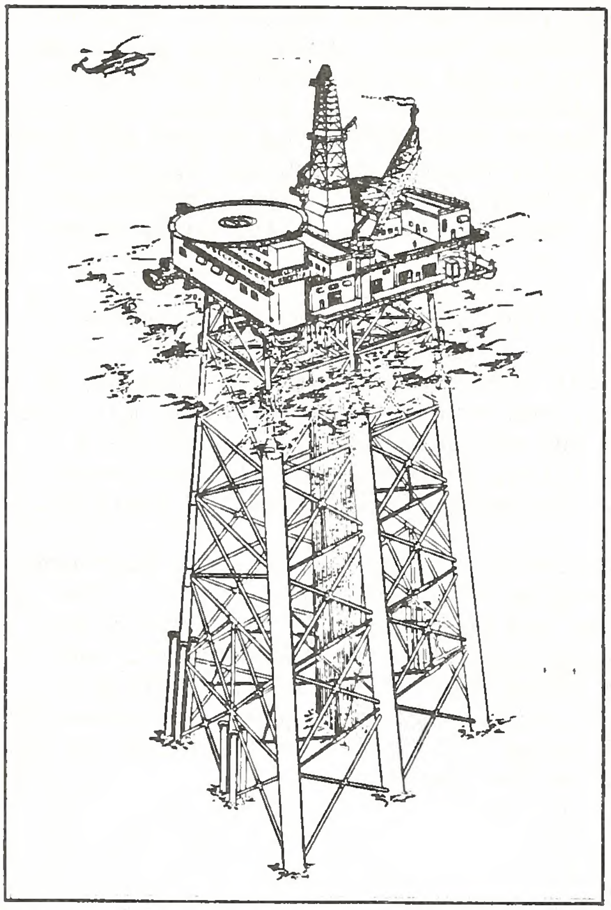
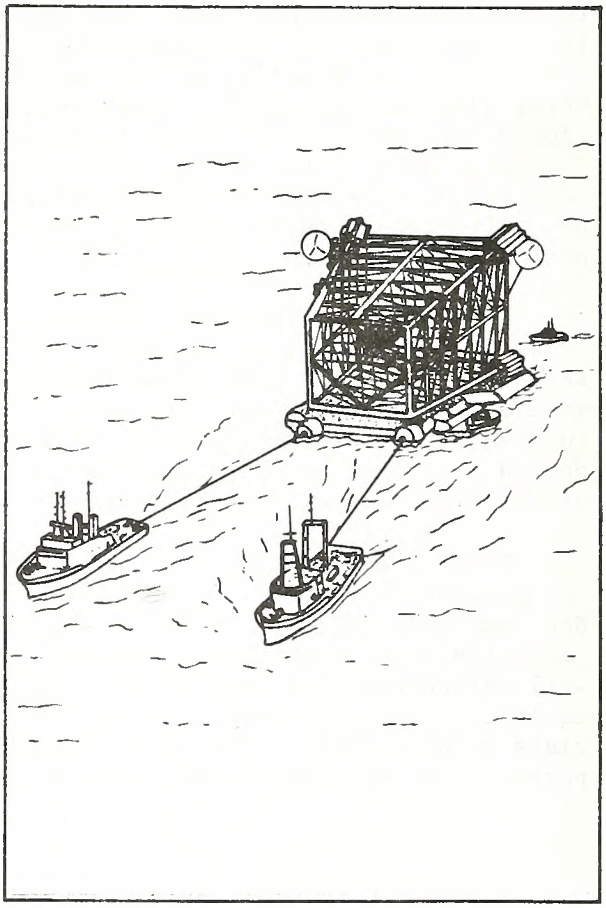


Figure 14
Towing the Steel Jacket
to the Drilling Site



Gravity platforms are a more recent development. Their stability arises from the weight of the platform resting on the sea floor rather than pilings driven into the sea floor (Figure 15). Gravity platforms are currently being used in the North Sea and are usually made of concrete. (A few steel gravity platforms are now in place off the West African coast.) Pre-stressed concrete is well suited to offshore production platforms because it resists corrosion, is relatively easy to build with, and does not suffer the same fatigue as steel under the stress of maximum wind and waves (such as that found in the North Sea). Concrete platforms, like steel fixed-pile platforms, are constructed at shore and towed to the drilling site (Figure 16). Concrete platforms tend to cost less than steel platforms as water depth above the field increases (though the economics will vary from one region to the next). They can also include enormous underwater storage tanks and mooring systems for loading tankers. The Phillips Oil Company operates a concrete gravity platform, standing in 230 feet of water in the North Sea, which has a storage capacity of one million barrels.

Figure 15
Concrete Gravity Platform

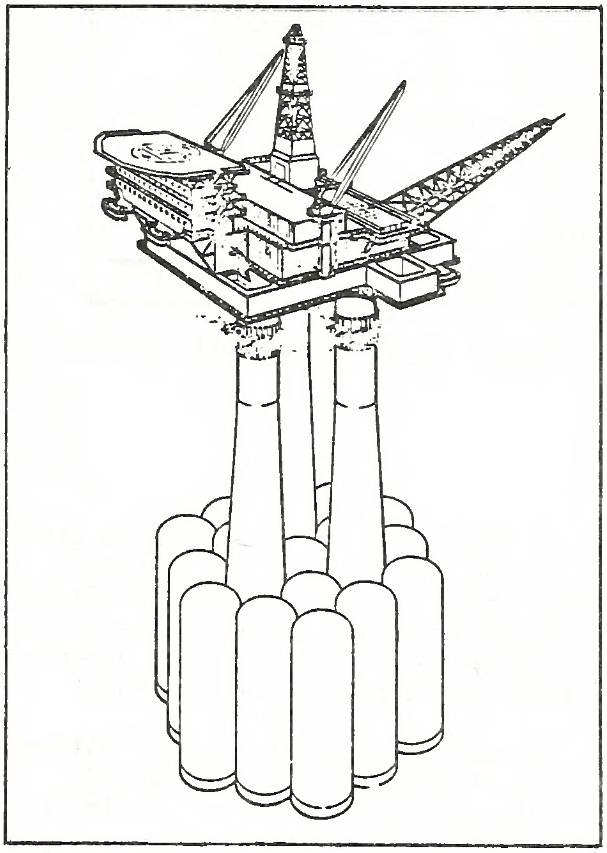
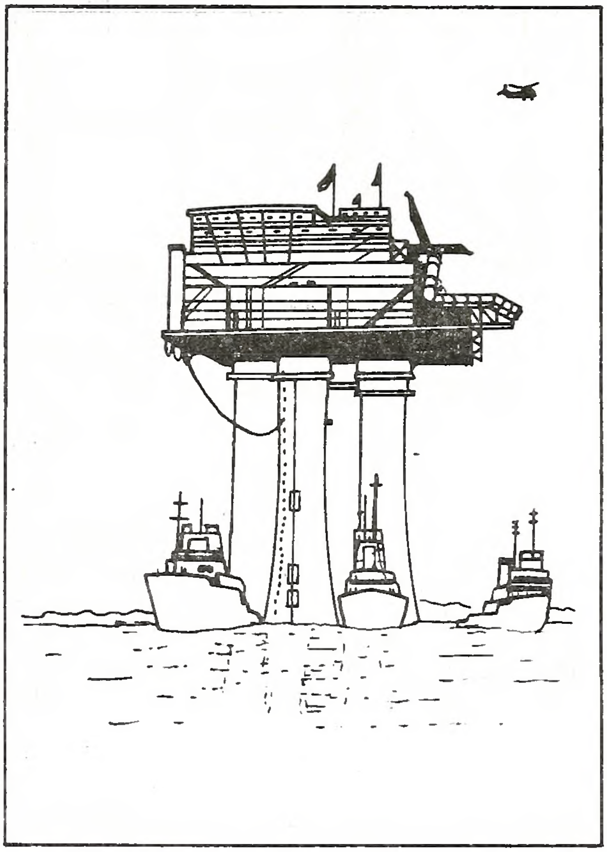
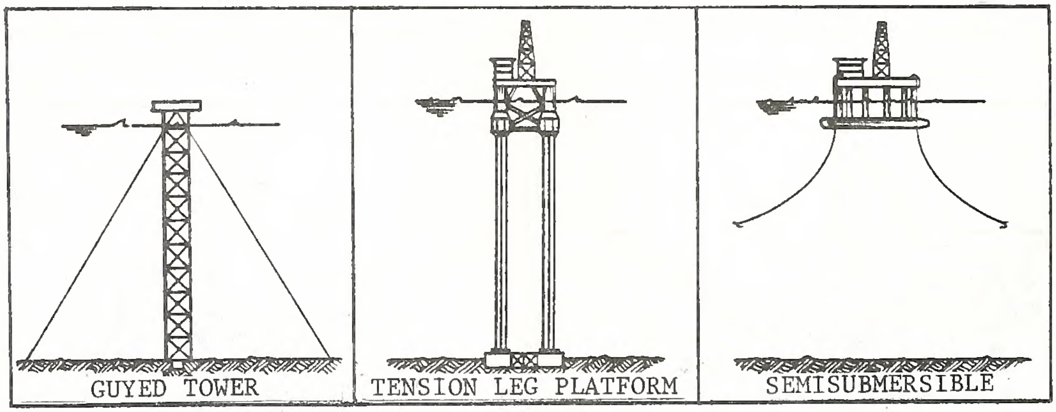


Figure 16
Towing the Concrete Platform
to the Drilling Site



A gravity platform can be used when the sea floor is hard and compact, as in the North Sea. Since the continental shelf of the eastern United States is predominantly soft sediments, all production platforms will probably be of fixed-pile type; gravity platforms would face a risk of uneven settling and other engineering problems. Other platform types are currently in the design stage for use in deeper waters, such as those tracts currently being leased off the North Carolina coast. Fabrication companies are working on hybrid concrete and steel platforms for all water depths and guyed tower platforms, tension leg platforms, and semi-submersibles for use in water over 800 to 1,000 feet deep (Figure 17).

Figure 17
Recent Developments in Deepwater Production Rigs

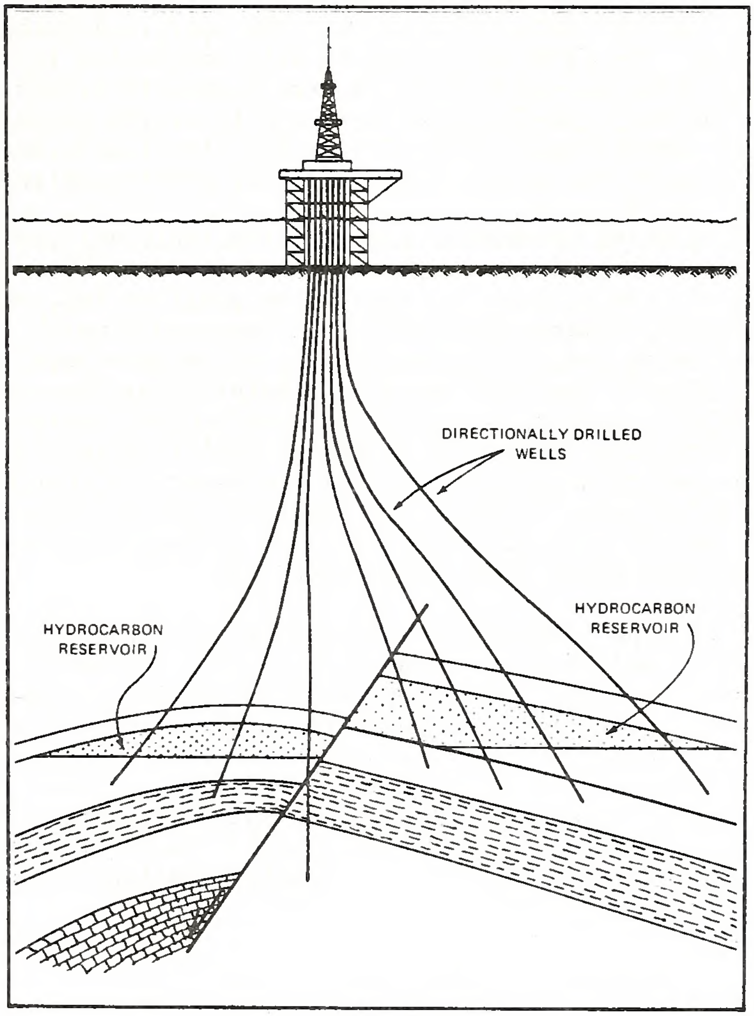


SOURCE: National Academy of Science, Outer Continental Shelf Frontier Technology, p. 32.

A platform's location within the lease tract will be influenced by lease stipulations, reservoir characteristics, bottom conditions (such as steep slopes and soft sediments), and ownership of adjacent tracts. When different oil companies own adjacent tracts which share a common hydrocarbon reservoir, they will try to establish a joint venture ("unitization") to ensure a maximum efficient rate of recovery. Unitization may be required by the USGS.

The costs associated with each platform rise dramatically as the oil and gas industry moves into deeper waters. Thus, the industry has developed methods for using as few platforms as possible to accomplish the same level of drilling and production. Directional drilling allows twenty-five to sixty wells to be drilled from a single platform. Whereas exploratory wells are usually drilled vertically, production wells are usually drilled at a slant (Figure 18). Directional drilling requires special rigs (mounted on the platform) which can rotate drill strings through drive pipes that are set at angles in the sea floor. Directional wells can have a horizontal range of up to one mile from the production platform. Directional drilling allows maximum penetration into the reservoir and can overcome problems arising when bottom conditions preclude placement of a platform directly above the hydrocarbon reservoir. Production platforms are usually designed with one or two derricks mounted on rails; a derrick can be readily moved over a new hole after each well is completed.

Figure 18
Directional Drilling



The pace of drilling is slower for field development than for exploration due to the complexity and accuracy of operations and the number of wells which must be drilled. Well "completion" is the series of actions that connect a well with the valves, pipelines, and other equipment which regulate the flow of oil and gas and transport them to shore. As each well is drilled, it is lined with concrete and capped until pipelines and/or tanker mooring systems are in place and onshore storage tanks and processing facilities are ready to receive the output.

After the pipes, tanks, and processing facilities are installed, sea water is pumped down the well casing to flush out any residual drilling mud. A perforation gun is then lowered into the well. When it reaches a point opposite a layer of oil or gas-bearing rock, the gun fires explosive charges through the casing and cement to establish a path for oil or gas to flow from the formation into the well bore. Another string of pipe, known as production tubing, is put down the casing as a conduit by which oil and gas come to the surface. Biocides are injected into the well to keep bacteria from clogging the flow. The final operation of well completion is installing a series of wellhead valves, or "Christmas tree," that is bolted to the top of the production tubing. The Christmas tree may be at the ocean floor or on the platform. It controls the rate of flow into the tubing and directs the oil and gas to the various processing facilities mounted on the platform.

After the wells are completed, the drilling equipment and most of the crew quarters are removed from the platform, and production equipment is installed. All that remains on the production platform is a maze of pipes, valves, coils, tanks, compressors, and other components which (1) separate oil and gas from water and other contaminants which have been trapped in the reservoir rock, (2) separate any associated natural gas from oil for separate flow into a pipeline, storage tank, or ship, and (3) pump natural gas back into a reservoir through a separate injection well to maintain reservoir pressure and thereby maintain production. All processes are continuously monitored by the platform crew. Their sole functions are maintenance and emergency control. Valves to regulate the flow of hydrocarbons can also be controlled by radio from shore or a nearby platform.

"Workover" is a periodic operation that improves well production by modifying downhole conditions to treat such problems as sand buildup and declining pressure. Workover includes procedures similar to the initial well drilling to remove sand, water, and any other substances which may accumulate in a well during production. Workover operations may also perforate the well casing at different depths to bring new reservoir layers into production. Safety equipment and any artificial pumping equipment are removed for inspection and maintenance before being reinstalled in or over the well. Adjacent wells are generally shut down for safety during workover operations.

Impacts on the Local Economy

During development drilling, the production platform requires a full drilling crew, which may number anywhere from 65 to over 200 workers (Clark et al., Recovery Technology, p. 83). The percentage of workers hired from the local labor pool and their skill distributions are similar to those associated with exploratory drilling. Once the wells have been completed and production equipment installed, the platform requires only about 16 workers. During the production stage, workover operations may raise platform employment for several months to the same level as development drilling.

Offshore supply needs are greater and more diverse during development drilling than during exploratory drilling. Employment will significantly increase during the field development stage at the onshore facilities which support platform operations. These facilities and their impacts are discussed in subsequent sections of this chapter.

Impacts on Natural Resources

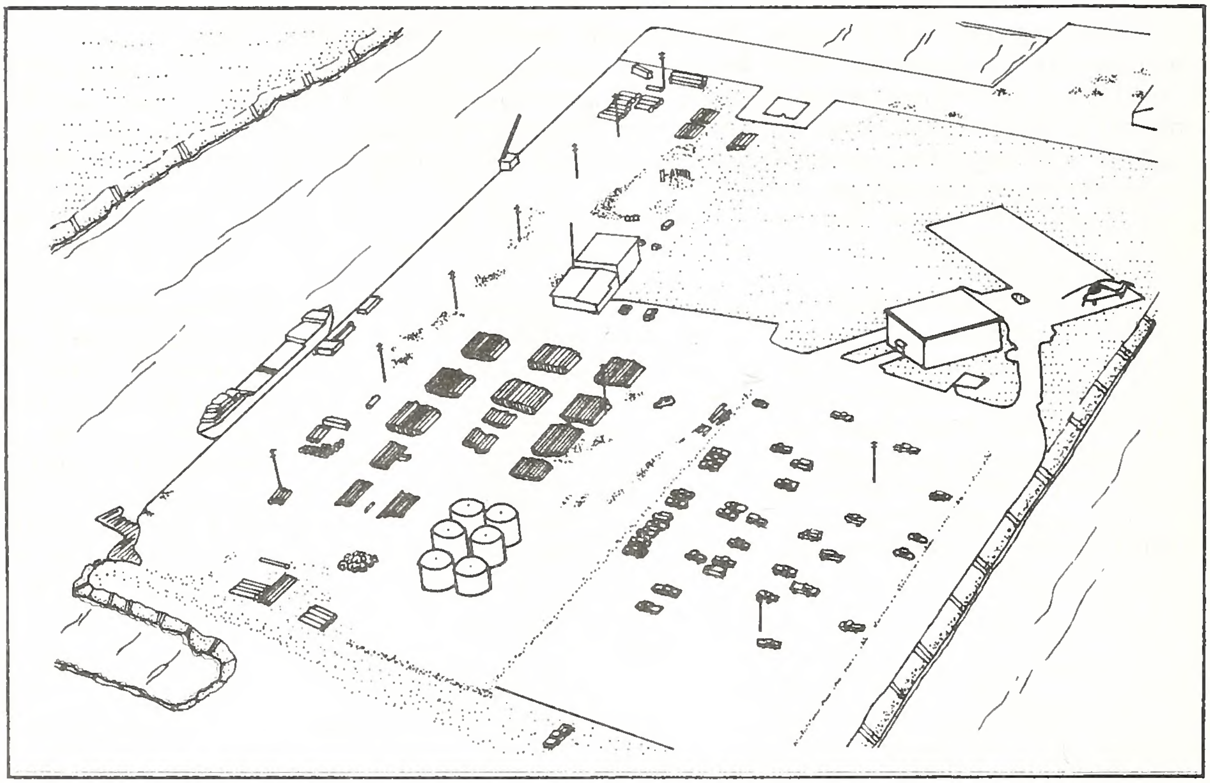
Development drilling occurs over a longer period of time and drills more wells from a single site than exploratory drilling, therefore creating a higher concentration of drilling mud and cuttings. These wastes may be mixed with petroleum, brines, and sulphur compounds; offshore disposal of them can smother species habitats and increase the turbidity and toxicity of the waters surrounding the production platform. The U.S. Environmental Protection Agency's OCS platform discharge criteria cover technologies and procedures for treating and disposing these wastes offshore.

Oil spills are a definite possibility from development drilling and production even though new technology has significantly reduced the chance for blowouts. The information on field structure and reservoir pressures obtained during exploration helps the offshore industry know what to expect and to use appropriate equipment to reduce the potential for spills and blowouts during development drilling.

Permanent Service Bases

The permanent service base performs the same functions during field development and production that the temporary service base performs during exploration. The permanent service base is much larger and supports a higher level of offshore activity. Permanent bases are set up by oil companies, drilling mud companies, and specialized OCS service companies to house administration and support services, to store materials, and to coordinate the flow of supplies and personnel to offshore platforms. The supply line to drilling operations must be orderly and efficient; any delay from a lack of supplies or equipment will increase drilling costs. Like temporary service bases, permanent bases contain dock space for supply boats and crew boats, a mineral processing area (for preparing drilling mud), loading equipment, open storage areas, warehouses, a machine shop, offices, and a helicopter pad (Figure 19). The base is likely to include space leased to cement firms, caterers, divers, drilling equipment distributors, and specialized repair firms.

Figure 19
Permanent Service Base



A permanent service base contains more extensive facilities and services than a temporary base in order to support the volume of supply vessel traffic associated with a higher level of offshore activity. Table 2 shows the supply needs of offshore operations for exploratory drilling, development drilling, and well workover. The scale and intensity of activity at a permanent service base is significantly greater than at a temporary service base for three reasons. First, up to 60 wells may be drilled and put into production from one offshore platform. Second, field development and production continue for a longer time period than exploration. Third, success at one tract stimulates additional exploration and field development on other tracts; the permanent service base may be supporting exploration, field development, and production activities all at the same time. Although the level of activity in most service industries will peak during field development and taper off during the production stage, there will be continuous demand for maintenance and supply services at the base.

Table 2
Materials Handled at Service Bases

	Exploratory Drilling (per rig per year*)	Development Drilling (per platform per year**)	Well Workover (per well)
Mud	2,568 tons	4,200 tons	41 tons
Cement	1,260 tons	2,288 tons	25 tons
Fresh Water	5,200,000 gals	8,200,000 gals	520,000 gals
Pipe	1,820 tons	3,816 tons	2 tons
Drilling Fuel	13,272 barrels	28,560 barrels	2,000 barrels
Transportation Fuel	12,800 barrels	25,600 barrels	(not available)

---

*based on four 15,000-foot wells per rig per year

**based on eight 15,000-foot wells per platform per year

SOURCE: NERBC, Factbook, pp. 1.15 and 1.28.

Temporary service bases are relatively small operations (five to ten acres), with the land leased on a short-term basis. A permanent service base will typically require 50 to 75 acres of land, depending on the intensity of offshore operations, which will be purchased or leased on a long-term basis (more than one year). Most of the land is used for open storage and warehouses; storage requirements will depend on whether or not materials suppliers are housed at the service base. At least 10,000 square feet are needed for administrative and communications offices (NERBC, Factbook, p. 1.25). Helicopter landing space will cover approximately one acre per offshore platform. These figures are estimates and will vary from base to base and region to region. Land requirements will also be a function of the available community infrastructure. If a permanent service base is located in a remote area or small community, additional space will be needed on the base for worker housing and ancillary services. If the base is located in a developed port city, workers will live throughout the community, and some ancillary services will occupy existing commercial space. As with temporary bases, a permanent base can realize economies of scale in all space requirements when supporting several offshore platforms.

The factors influencing the location of temporary service bases also influence the siting of permanent service bases. These factors include (1) access to water, roads, rail, and airports, (2) the existence of other temporary and permanent bases in the leasing region, (3) proximity to offshore operations, and (4) proximity to the social and service infrastructure of a frontier community.

A permanent service base requires approximately 200 feet of dock frontage for each platform being serviced, with a minimum channel depth of 15 to 20 feet (NERBC, Factbook, p. 1.26). Four supply boats and one crew boat will service each platform during development drilling. During production and workover, each supply boat can usually service two platforms; no crew boats will be needed since crew transfers are likely to occur by helicopter. Road and/or rail access is essential for a service base; large quantities of drilling mud, cement, pipes, fuel, and other materials must be brought into the base for transportation to offshore platforms. Deliveries of supplies to the service base may also be made by boat. Although a permanent base may require more helicopters than a temporary base for transporting personnel and special equipment, the helicopters are still rented from a contractor and return to the contractor's heliport at the end of each day. Production and workover operations require about half as many helicopters as development drilling. Permanent bases tend to locate near communities with adequate airports for bringing in personnel and maintaining contact with industry operations in other regions.

The efficiency of a service base is measured by "turnaround" time -- the time it takes a vessel to dock, load supplies and crew, and return to offshore platforms. Service bases should be located away from commercial fishing and recreational boating facilities to avoid delays caused by harbor congestion.

The location of temporary bases established during exploration or permanent bases existing elsewhere in the leasing region may prove convenient for field development and production. A temporary service base may have inherent limitations to expansion for supporting the level of activity associated with development drilling. If the offshore field is a considerable distance from an existing temporary or permanent base (200 miles or more), oil and service companies may look for a closer site which will minimize the cost of transporting supplies and workers. This may occur even if an existing base is sufficient in all other respects.

Permanent service bases tend to locate in and near established communities with an adequate labor pool, utilities infrastructure, and social infrastructure. Permanent bases require a full complement of utilities. Their workers require a full complement of housing, social services, and entertainment facilities. Oil companies are sensitive to the needs of their workers, whether they are brought in from other areas or contracted from the frontier community.

Impacts on the Local Economy

The impacts of permanent service bases vary with the number of platforms being serviced and the stage of OCS development. Activity is heaviest during development drilling, especially when the base is supporting exploration, development, and production at the same time.

Employment at a service base varies with the stage of field development. If a new permanent base is established, 20 to 90 workers will be required for a one-year construction period, depending on whether the base is set up at existing port facilities or constructed from scratch. When the base is in operation, 50 to 60 service base jobs will be provided for each platform engaged in development drilling, up to half of which may be filled by local workers (NERBC, Factbook, p. 1.29). Worker requirements fall during the production stage, with temporary increases during well workover. Table 3 shows the labor requirements of a service base at different stages of offshore activity. Most jobs require semi-skilled workers, which should be available in any port city. Workers with specialized skills may be brought in from other regions. The number of local people employed at the service base is almost constant. The average wage rate will probably be higher than for traditional waterfront work; workers may be attracted away from other marine industries, such as fishing.

Impacts on Natural Resources

The environmental impacts of permanent service bases are the same as those of temporary service bases. However, the impacts will be more significant because of the larger scale and more intense activity of permanent bases. Permanent bases store and handle a larger volume of materials

Table 3
Service Base Labor Requirements for Different OCS Stages

	Exploratory Drilling (per rig)	Development Drilling (per platform)	Production (per platform)
Supply boat	30-36	30-36	16
Crew boat	6	6	----
Helicopter	3	3	3
Wharf and warehouse	4-6	9	3
Total	42-54	48-54	22
Local personnel	20-22	20-22	18-22

SOURCE: Clark et al., Recovery Technology, p. 130.

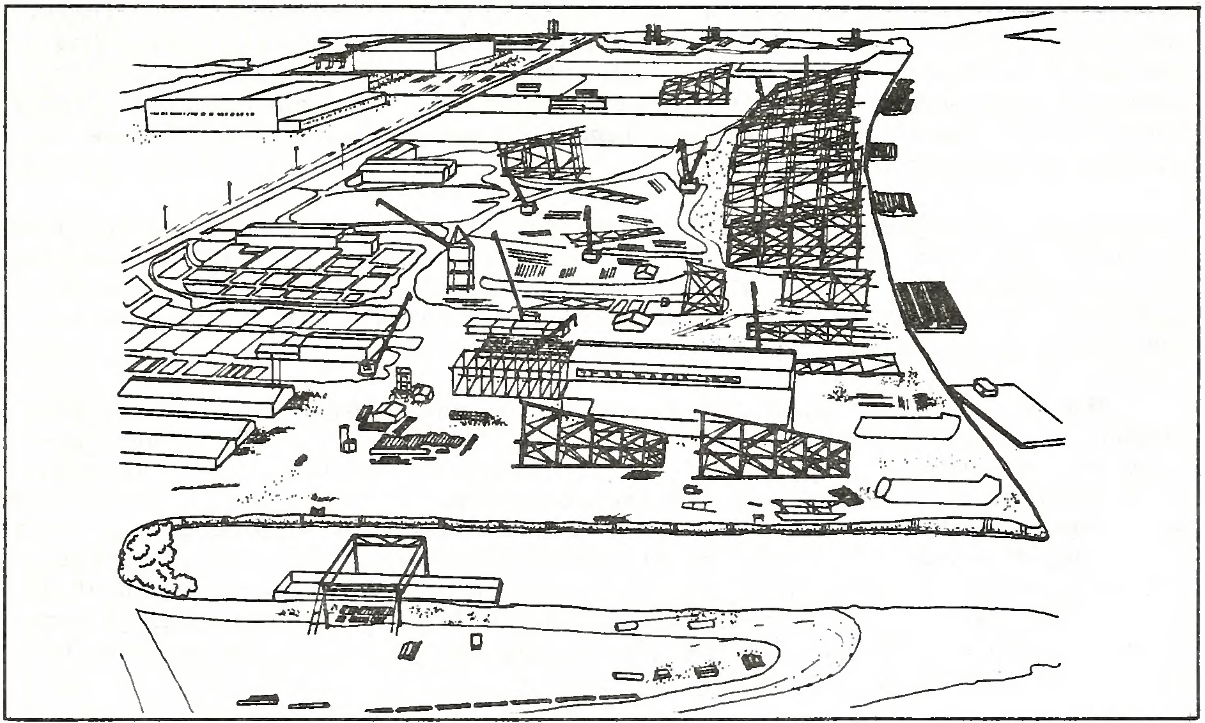
(Table 2) and operate for a longer period of time. A permanent service base will probably not be set up in a single construction phase; different components of the base will be constructed in response to the offshore demands of different stages of field development. The heavy use of supply boats may necessitate redredging the harbor channel. Nearly all such vessels have bow thrusters which can cause scouring and siltation.

Platform Fabrication Yards

Offshore platforms used in the field development and production stages are constructed at platform fabrication yards to meet the specific needs of each drilling site. The fabrication yard has a greater impact on the coastal community than any other facility required by offshore oil and gas development. The yard requires more waterfront land, more industrial materials, and a larger workforce. These requirements will vary slightly depending on whether the yard produces steel fixed-pile platforms or gravity platforms. Since steel fixed-pile platforms are more likely to be used on the Atlantic OCS, the following discussion presents the construction process and fabrication yard requirements associated with them.

A full range of construction activities occurs at the fabrication yard. Flat steel plate is rolled into tubing, which is then welded together to form the platform jacket. The jacket is constructed outside, laying on its side at the waterfront or in a dry dock (Figure 20). The completed jacket is

Figure 20
Platform Fabrication Yard



rolled by dollies or rails onto a barge and towed to the drilling site, where one or two derrick barges upend the jacket and slowly sink it to the sea floor. The platform's deck and associated modules (drilling rigs, crew quarters, operations equipment, helipad, etc.) are built in large construction sheds, loaded onto barges, and carried to the drilling site. Derrick barges attach the deck and modules to the steel jacket.

A platform fabrication yard contains (1) an open waterway or dredged channel to the sea, (2) dock space for receiving materials and loading completed components, (3) open space for jacket assembly, (4) large sheds for constructing decks and modules, (5) a pipe-rolling mill, (6) a shop that prepares pipe and plate for assembly, (7) welding racks, (8) a sand-blasting and painting shop, (9) an electrical shop, and (10) various warehouses, repair shops, open storage areas, and offices.

In siting a platform fabrication yard, the fabricator looks for a large, flat, low-lying parcel of waterfront land which is an economically practical distance from offshore fields. The acreage required for a yard depends on the number of platforms likely to be constructed at any one time during the life of the yard. The smallest existing fabrication yard covers 50 acres. Most yards are considerably larger, requiring 200 to 1,000 acres, with a 300-acre average size. About half of the land is used for fabrication and half for storage and support activities (warehouses, offices, welding shops, etc.). The amount of land a company actually purchases or leases may be even larger depending on the land's cost, its availability, and the company's desire for expansion space. Brown and Root, the Houston-based construction firm, has purchased 2,000 acres of land in Northampton County, Virginia, on which it plans to build a 980-acre platform fabrication yard. Many fabricators prefer short-term lease options over the purchase of land, with renewal clauses stating no maximum lease period.

Fabricators prefer to locate yards on cleared land with no existing docks or buildings; this allows the fabricator to lay out the yard for maximum production efficiency. The land must be well-drained, have a low water table, and have a load-bearing capacity of at least seven tons per square foot (NERBC, Factbook, p. 8.18).

The wharf space required at a fabrication yard depends on the size and number of platforms being constructed at any one time. Steel platform jackets are constructed perpendicular to the wharf; the required wharf length is a function of the length of the jacket's base, the space needed to maneuver equipment around the jacket, and the number of platforms in production. Additional wharf space may be needed for unloading construction materials that arrive by boat. Steel platform yards require a dockside channel depth of 15 to 30 feet. The channel should be from 200 to 300 feet wide and have a vertical clearance of 210 to 350 feet for safely navigating platforms from the yard to the sea (NERBC, Factbook, p. 8.19).

The transportation of raw materials, fuel, equipment, parts, and workers requires rail and highway access to the yard. Access to an airport facilitates the shipment of small freight and out-of-town personnel. The level of traffic will vary with the number of platforms being constructed at one time and can be intense, especially in a small community, since up to 550 workers may be needed for each platform (NERBC, Factbook, p. 8.2.). It is difficult to obtain specific information on the transportation requirements of a fabrication yard until offshore oil or gas discoveries determine the demand for platforms and the yard begins operation.

Except when all other locational factors are equal, the availability of skilled labor is not critical in the site selection decision, even though a fabrication yard employs hundreds of steel workers. The company may bring in skilled workers and management staff from Gulf coast yards to provide a nucleus of workers who understand the platform fabrication process and can train local workers.

The most important considerations in determining whether or not to construct a new steel platform fabrication yard in a frontier region are (1) the size of the offshore find, which determines the level and timing of the demand for platforms, (2) the portion of the platform market that the fabricator believes it can capture, (3) the distance from the offshore field to existing fabrication yards, and (4) the capital and operating costs of a new yard.

Though land for a new yard may be purchased or optioned years before a lease sale, a fabrication company will construct the facility only after a significant offshore find has occurred and oil companies formulate schedules for field development. While the oil company delineates the extent of an offshore field, the fabricator meets with oil company representatives to discuss the number of platforms needed, preliminary specifications for platform design, and a platform delivery schedule.

Having a fabrication yard ready for production soon after the discovery of an offshore field allows the fabricator to compete effectively against other firms and allows offshore operators to more quickly begin oil and gas production. The strategies of fabricators and oil companies are not always compatible. The fabricator wants to avoid facility construction and other major investments in a new yard until it receives an initial order for platforms. The oil company benefits from having the yard fully developed when it places the initial order, thus avoiding costly delays in offshore production.

There is no consensus on what constitutes enough of a market for platforms to justify building a new platform fabrication yard. Investment policies vary from one fabrication company to the next. After determining what portion of the platform market it can capture in a frontier region, the fabrication company will compare the initial capital costs and operating costs of a new yard with the cost of building the platforms at an existing yard and towing them to the offshore field. The outcome of this balancing decision rests in the volume of platform sales and distance to the offshore field. The cost of towing several platforms from an existing yard to a distant field may outweigh the cost of setting up a new yard in the frontier region. A new yard will not be constructed until there is a firm demand for platforms in the frontier region since at least three platforms must be built before a new yard will recoup its initial investment and operating costs (Clark et al., Recovery Technology, pp. 160-161).

In anticipation of the demand for platforms in a frontier region, a fabrication company may purchase or obtain an option on a suitable tract of land before the lease sale occurs. This allows the fabricator to proceed with site layout, facility design, zoning applications, other permit applications, and environmental impact assessments; the fabricator will then be ready to rapidly construct the yard once it receives platform orders. Brown and Root has already purchased 2,000 acres in Virginia and an option for 400 acres in Oregon as sites for new platform fabrication yards.

Unless there are major resource discoveries, there will be no major fabrication yards established in frontier areas of the United States. Purchasing land and securing land options do not mean that a new yard will eventually be constructed. Long towing distances from existing yards to the frontier region favor constructing a new yard, but the high capital outlays required for a new yard favor construction at existing yards.

There are currently four fabrication yards in the United States which receive all major domestic platform contracts: (1) the Brown and Root yard near Houston, Texas, (2) the J. Ray McDermott yard near Morgan City, Louisiana, (3) the Avondale yard, also near Morgan City, and (4) the Kaiser Steel Corporation yard in Oakland, California. Each of the Gulf coast yards occupies about 1,000 acres, has the capacity to simultaneously build two or more platforms, and supplies platforms to domestic and international markets. Roughly 20 percent of the Brown and Root yard's production goes to foreign countries (Clark et al., Recovery Technology, p. 151). The four existing yards can easily handle the demands for platforms in U.S. frontier areas unless new resource finds are large.

It is not likely that a new platform fabrication yard will locate in North Carolina. Brown and Root's Virginia site is in a central location to serve oil and gas production which may occur off the coasts of New England, the Mid-Atlantic states, and the South Atlantic states. Brown and Root has obtained the necessary zoning approval and is prepared to proceed with site development should the demand for platforms warrant it. If Atlantic fields do turn out to be quite large, the probability will increase for another fabrication yard to locate somewhere along the Atlantic coast.

In addition to the unpredictability of platform demand in new offshore fields, the capacity of existing shipyards may influence whether or not new platform fabrication yards will be constructed. Shipyards may enter the platform fabrication business in order to use or expand existing facilities by constructing platform jackets, decks, or modules and towing them to drilling sites. This would reduce the need for new fabrication yards.

Impacts on the Local Economy

Employment at a fabrication yard will vary depending on the number of platforms simultaneously under construction. Setting up the yard will require roughly 500 workers (Clark et al., Recovery Technology, p. 156). Labor estimates during yard operations range from 250 to 550 workers per steel platform (NERBC, Factbook, p. 8.21). Up to 90 percent of this workforce may be hired from the local labor pool if skilled workers are available. Some economies of scale in the number of workers needed may appear at large yards. Brown and Root estimates a peak requirement of 1,500 workers at its Virginia yard, where up to nine platforms may be fabricated at the same time (Urban Pathfinders, Brown and Root Impact Study, p. 4).

Almost half of the workers at a yard are welders and shipfitters. Twenty to 25 percent of the workers are painters, machinists, and electricians. Another 20 to 25 percent work in other construction crafts, maintenance, storage, and general support operations. Roughly ten percent are supervisory, engineering, and administrative personnel (NERBC, Factbook, p. 8.21). Fabricators will recruit and train unskilled and semi-skilled workers when there are not enough skilled workers in the area labor market. The companies may set up their own training departments or provide training in the necessary skills through the local school system. Many skilled workers and management staff may be brought in from existing fabrication yards on the Gulf coast. Wages at fabrication yards tend to be higher than wages in other sectors of the local economy; thus, the yard may draw workers away from other activities.

Since the platform fabrication industry depends on contracts with oil companies, yard workers are vulnerable to massive layoffs and staff increases. Platforms usually take two years to construct. The most stable and efficient use of the yard's workforce requires at least two platforms to be under construction at one time; this usually requires signing a new contract each year (Baldwin and Baldwin, Onshore Planning for Offshore Oil, p. 76). Small communities may experience significant economic disruption when there are gaps in the yard's workload.

A platform fabrication yard can have a significant impact on local transportation facilities and social services due to the amount of raw materials and number of workers at the yard. Fabricators tend to locate in relatively undeveloped areas which seldom have the infrastructure to support large-scale industry. Highways and railroads may have to be upgraded to support higher traffic volumes and heavier equipment. The influx of workers and their families, who will tend to live in or near the community, may substantially increase the local demand for housing, schools, police and fire protection, health care, and water and sewer systems over a short period of time (from two to ten years). Local governments will have to devise schemes for economically providing these services and facilities at a pace commensurate with demand.

Impacts on Natural Resources

The environmental impacts of a platform fabrication yard will depend on the number of platforms being constructed and the nature of the site. More platforms mean more industrial activity occurring at the same time. If the yard is established on an undeveloped site there may be significant dredging, filling, and other site alterations involved in setting up the yard.

Site Alteration and Construction -- The impacts of site preparation will be minimal if the yard is constructed in an underutilized developed harbor with an adequate channel depth. Existing structures will probably have to be torn down. Machinery emissions, noise, and dust may have a short-term negative impact on adjacent properties.

Impacts will be more significant if the yard is constructed on an undeveloped site. Wetlands and other fragile habitats may be destroyed by massive clearing and filling. Runoff from the construction site may carry sediments into adjacent wetlands and waterways and disturb or destroy fish and wildlife. Shoreline alterations and channel dredging may increase the turbidity of the waterway, smother bottom-dwelling species, and alter water current and erosion patterns in the vicinity of the yard. Dredging to maintain the channel once the yard is in operation may have similar effects.

Water Requirements -- A yard which contains pipe-rolling processes and produces two to four steel platforms each year could use up to 1.24 million gallons of water per day (NERBC, Factbook, p. 8.20). Brown and Root estimates water demand at its proposed Virginia yard, which does not contain pipe-rolling facilities, to be about 100,000 gallons per day (Urban Pathfinders, Brown and Root Impact Study, p. 30). This water demand could place a burden on existing supplies of surface water and groundwater depending on the support capacity of existing water systems.

Wastewater and Runoff -- Cooling water, process water, and sewage will be generated by a steel platform fabrication yard. The industrial processes and level of activity at the yard will determine the amounts of each type of wastewater. The process and cooling waters used in pipe-rolling, welding, corrosion prevention, and other metal fabrication activities may contain large quantities of particulate matter, heavy metals, and anti-fouling chemicals. These substances may be taken up by plants and animals in the receiving waters, having negative effects on these organisms and those which feed on them. Process and cooling waters containing harmful quantities or types of pollutants should be treated or recycled in accordance with state and federal environmental regulations before being released into coastal waters. Sewage from the yard will either be treated at the yard or piped to an existing sewage treatment facility.

During platform fabrication, runoff from the yard is likely to be contaminated by sediments, heavy metals, process chemicals, and petroleum products. The size, activities, and control practices of the yard will determine the types and levels of runoff contamination. The effects of these contaminants will depend on their toxicity, the initial quality of adjacent waters, and the sensitivity of aquatic organisms.

Increased runoff due to soil compaction and impervious surfaces at the yard may decrease the rate of groundwater recharge in the vicinity of the yard. Whether or not this promotes salt water intrusion will depend on the decrease in recharge levels, the size of the aquifer, and the direction of groundwater flow.

Solid Waste -- Fabrication yards will generate large volumes of solid waste, much of which can be reused, sold as scrap, incinerated, or placed in a sanitary landfill. There will be four types of solid waste: (1) packaging and shipping materials, such as cardboard, wooden crates, and spools, (2) scrap metal, such as strapping and steel remnants, (3) containers and other debris contaminated with oil or hazardous chemicals, such as paint cans, and (4) general rubbish. Wastes contaminated by oil or hazardous substances should be handled and disposed so that the substances are not released into surface water, groundwater, or the air.

Air Emissions -- Air emission sources at a fabrication yard include sandblasting, painting, and transportation equipment. Sandblasting prepares the platform's metal surfaces for painting and generates considerable quantities of sand and metal dust. The size, density, shape, and surface characteristics of these particles, and whether the sandblasting is done indoors or outdoors, will determine which emission control systems (filters, wet-scrubbers, etc.) will be used at the yard.

Painting the platform's components generates high emission levels from the evaporation of aromatic hydrocarbons, ketones, solvents, and other paint constituents. Volatile constituents average about 50 percent of the total volume of the paint; approximately 1,120 pounds of evaporate will be emitted per ton of paint used (NERBC, Factbook, p. 8.24). Activated charcoal absorbers can remove 90 percent of these emissions for safety when painting occurs indoors. Painting also generates particulate matter, which may be reduced by filter pads or water curtains.

The heavy trucks and machinery used to deliver and move large quantities of steel and other materials release carbon monoxide, hydrocarbons, sulfur oxides, and nitrogen oxides from the combustion of gasoline and diesel fuel. Heavy automobile traffic (a function of the number of workers) generates similar emissions. The overall impact of these emissions will depend on (1) the type of equipment used, (2) the size and output of the yard, (3) existing air quality at and near the site, and (4) local meteorological conditions.

Noise -- Heavy equipment used in platform fabrication and on-site power generators will produce considerable and continuous levels of noise, ranging from 80 to 115 decibels, which are above the average level of most communities (NERBC, Factbook, p. 8.28). The impacts of this noise will vary depending on the nature of adjacent uses (urban or rural, industrial or residential), local terrain, and noise control devices used at the yard. Mufflers and other sound absorbers can reduce on-site noise and its off-site effects. Buffer zones around the yard will permit the noise to attenuate before it reaches adjacent properties. The attenuation distance required for yard noise to reach ambient community levels will depend on the nature of adjacent uses. Brown and Root has agreed to protect adjacent farms and homes from industrial noise (Urban Pathfinder, Brown and Root Impact Study, p. 35).

Aesthetics -- The bases of steel platforms under construction at the yard, laying on their sides, can be over 200 feet tall. The yard may operate 24 hours a day, seven days a week. Tall platforms, large construction sheds, and industrial lighting may have a significant visual impact on the surrounding community. This impact can be reduced by appropriate landscaping and buffer zones. Again, the level of impact will depend on the nature of adjacent land uses.

Pipelines

After exploratory drilling discovers and delineates an oil and gas field, the offshore industry must decide how to transport the oil and gas to onshore terminals, refineries, and gas processing plants. Oil may be transported by pipelines or tankers, which load oil from mooring stations at or near the platform. Gas is almost always brought to shore by pipeline; the cost of liquifying gas at the platform and transporting it by ship is prohibitively expensive in most cases. Pipelines are generally safer and more economical than tankers and barges. Pipelines also permit continuous transportation of oil and gas to shore; they are less susceptible to weather conditions which can temporarily shut down tanker operations. All offshore gas and 98 percent of all offshore oil produced in the United States is brought to shore by pipelines (NERBC, Factbook, p. 3.6). Pipelines will likely be used to transport oil and gas from most new offshore fields in the United States (Clark et al., Recovery Technology, p. 88).

The factors influencing the choice between pipelines and tankers include (1) the size and composition of the offshore field, (2) its distance from shore, (3) weather conditions, (4) oceanographic conditions, and (5) the availability of existing oil terminals and refineries in the frontier region.

The probability that a pipeline will be constructed increases with the size of the oil and gas find. An offshore pipeline must be able to handle large volumes to justify its construction, which may cost over one million dollars per mile. As the field's distance from shore increases, so does the cost of laying a pipeline. Tankers may be used initially until the economics of pipeline construction improve during the productive life of the field or adjacent fields are discovered and developed. If there is an insufficient amount of gas to justify the investment necessary to build the pipeline, the gas will be reinjected into the formation or burned off.

Tanker transportation from the platform to shore is not an attractive alternative in areas with frequent adverse weather conditions; loading operations are hampered by strong winds and high waves. Loading delays can cause expensive temporary shutdowns and interruptions in the supply of crude oil. This may make pipeline construction more economical in the long run.

Oceanographic conditions, such as water depth, bottom currents, sea floor topography, and sea floor stability, may influence the cost and engineering feasibility of a pipeline. Extreme water depths render pipelines infeasible. Strong bottom currents and adverse sea floor conditions may require engineering solutions which are prohibitively expensive. If an oil company has access to a marine terminal in the region capable of receiving oil and shipping or piping it to a refinery, the company will be more likely to use tankers than build a pipeline, particularly for small fields or fields far from shore.

The number of pipelines needed to serve offshore fields in a frontier region depends on the location of oil and gas fields and onshore processing facilities, the number of companies involved, and government policies regarding pipeline sharing. An offshore pipeline system consists of (1) a pressure source, (2) gathering pipelines, (3) main pipelines, (4) intermediate pressure boosting stations, (4) a landfall, and (5) an onshore destination.

Formation pressures may be sufficient to drive natural gas ashore without the aid of pumps and compressors. Oil pipelines usually require pumping equipment. Pumps and compressors are located on offshore platforms and contain safety equipment to prevent excessive pipeline pressure.

The main pipeline may originate from a single production platform or from several platforms connected by a network of "gathering" pipelines. Gathering pipelines have smaller diameters than the main pipeline and eliminate the need for a large number of small, less economical pipelines connecting offshore platforms and onshore facilities. Gathering systems are more frequently used as distances increase between the field and the shore.

Main pipelines are designed to meet the volume and flow rate requirements of offshore production. The diameter chosen for the line is a function of the production rate of the field, the desired operating pressure, and bottom conditions along the pipeline route. The offshore industry tries to locate pipelines along the shortest possible route from the platforms to the shore.

Intermediate pressure booster stations may be necessary along the pipeline route depending on the length and diameter of the pipeline, the topography of the sea floor, and the nature of the fluids being transported (viscosity, specific gravity, and whether oil and gas are being pumped simultaneously).

The landfall is the location where the pipeline reaches shore. Additional onshore facilities may be located at or near the landfall, depending on the characteristics of the oil and gas and their final destinations. Gas processing plants, which clean the gas and separate its various components, are often located along the onshore pipeline route between the landfall and the nearest commercial gas transmission line. Pumping stations, oil storage facilities, and marine terminals may locate near the landfall if oil is to be transported by tanker or overland pipeline to a nearby refinery or refineries in other regions.

The onshore destination of crude oil is the refinery. The onshore destination of natural gas is the gas processing plant and commercial transmission line. The location and ownership of the refinery may influence transportation decisions. If a refinery exists in the frontier region, the oil will be pumped from the landfall or marine terminal to the refinery via an overland pipeline. If the oil is destined for a refinery in another region, it may be (1) shipped directly from offshore stations to the other region, (2) shipped to the other region from a marine terminal in the frontier region, or (3) piped from the frontier region landfall to the other region via an overland pipeline network (if one exists).

Pipelines do not require much land once they come ashore, usually a minimum right-of-way between 50 and 100 feet wide. Pipeline companies will purchase some of this land in fee simple and some in easements for construction and maintenance. The landfall itself may be nothing more than a strip of land 100 feet wide, depending on the physical characteristics of the site and the equipment used in pipeline construction. Pumping stations near the landfall and elsewhere along the pipelines may require 40 acres of land to house pumping equipment, storage tanks, and a small office. Gas processing and treatment plants will require 50 to 75 acres somewhere along the pipeline right-of-way. Marine oil terminals will require about 60 acres of waterfront land with a channel depth of 30 to 35 feet.

Pipelines can be owned by oil companies or gas transmission companies. Offshore natural gas recovered by an oil company may be sold at the platform to a gas transmission company, who constructs a pipeline to bring the gas to shore and connects it to the company's existing transmission network. Oil companies will build their own pipeline if the volume of oil justifies construction expenditures. Oil companies and gas companies may build a common carrier pipeline (1) if a number of oil companies are producing on adjacent tracts, (2) if the companies do not have enough oil or gas individually to justify construction, (3) if economies of scale exist, or (4) if economics favor the separation of oil and gas onshore rather than offshore.

Pipeline design (diameter, wall thickness, and number of pressure booster stations) depends on many factors. These include the composition of the stream (gas, oil, or a combination of the two), the characteristics of the stream (pressure, temperature, and specific gravity), the production rate, desired operating pressures and capacities, and whether or not oil-gas separation occurs onshore or on the platform. Even though pipeline construction is expensive, building separate pipelines for oil and gas is usually more economical than pumping them through one line. The flow of oil and gas mixtures is less energy-efficient and requires more complex equipment than the flow of pure gas or oil (NERBC, Factbook, p. 3.24).

Offshore pipeline routes are selected to minimize the total cost and engineering difficulties involved in constructing and operating the total pipeline system. During the exploration stage, the oil and gas industry begins selecting generalized routes, or "corridors," to carry potential finds to shore. The most important criterion for preliminary corridor selection is the most direct path from offshore tracts to the coastline. This "straight-line" strategy minimizes pipeline construction and operation costs, which may exceed one million dollars per mile. Refinements to this route will be made to avoid geological hazards, to more easily connect the offshore system to existing onshore transmission or processing facilities, and possibly to avoid fragile onshore and offshore ecosystems. Offshore geological hazards include soft or unconsolidated sea floor sediments, strong bottom currents, mobile sand waves on the sea floor, submarine deltas, slump areas, buried channels and valleys, steep slopes, and active faults. These hazards can expose a buried pipeline, hamper pipeline construction, and place stress on or rupture a pipeline. They are identified by various oceanographic and geologic tests. The routing decision may also try to avoid fragile, small, or unique offshore habitats and fisheries areas. Much of the information on geological hazards and offshore ecosystems may already exist as a result of previous offshore research by private organizations and government agencies.

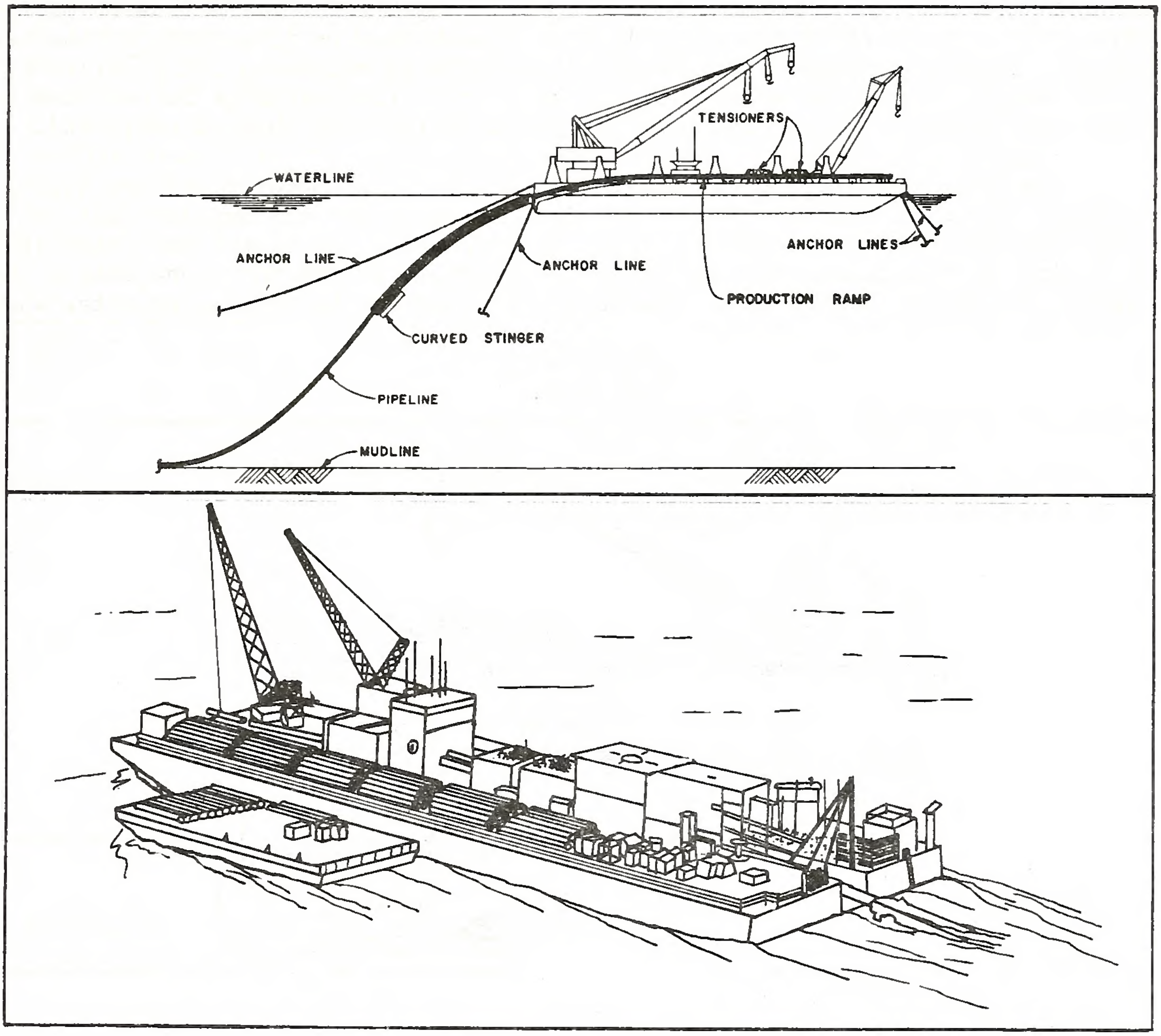
A number of federal agencies have jurisdiction over corridor siting and pipeline design. The U.S. Geological Survey has general jurisdiction over use of the outer continental shelf's resources. The Bureau of Land Management approves pipeline rights-of-way. The Department of Transportation's Office of Pipeline Safety has standards for pipeline design, construction, and operation. The Federal Energy Regulatory Commission certifies gas pipelines. The Army Corps of Engineers regulates activities which may interfere with navigation. The regulatory authority of state agencies takes effect once the pipelines enter state waters; North Carolina has jurisdiction over the sea floor within three miles of the mean high water line.

While the general location of a landfall is primarily determined by the "straight line" strategy, the specific landfall site selection is determined by the physical characteristics of the shoreline and the company's onshore facility plans. The landfall should allow a flat or gently sloping approach to shore and a gentle transition from the marine environment to the land environment. The shore approach should have sufficient sand depth to provide at least ten feet of cover over the pipeline at the tidal margin and seven feet of cover at a water depth of 50 feet. In choosing pipeline landfalls, companies avoid highly eroding shorelines and dune systems, high-velocity littoral currents, unstable sediments, steep slopes, and areas with large tidal fluctuations. These factors hamper pipeline installation and subsequent site restoration and threaten the structural integrity of the pipeline. Installation and site restoration may also be difficult if the pipeline lands at a wetland rather than a sandy beach. Inland from the landfall, as the pipeline is constructed to onshore facilities, pipeline companies may encounter other geological hazards or fragile habitats.

A gas pipeline company prefers a landfall within a reasonable distance from a piece of land large enough to house a gas processing plant, which needs not be constructed at the landfall itself. An oil company wishing to transfer oil from the pipeline to tankers prefers a landfall near an existing marine terminal or near land suitable for development as a marine terminal. If the company intends to pipe oil further overland to a refinery or an existing marine terminal, the company may seek the shortest possible route from the offshore field to the onshore facility, with the landfall at some point between the two. This will tend to be outweighed by the desire to follow the shortest possible route from the field to the shore and then to the onshore facility; offshore pipeline installation is at least twice as expensive as onshore installation.

Other economic factors come into play when the company is choosing a landfall and overland pipeline route. These include: (1) acquisition costs for rights-of-way, which vary with land use and ownership, (2) construction

Figure 21
Lay Barge Operations



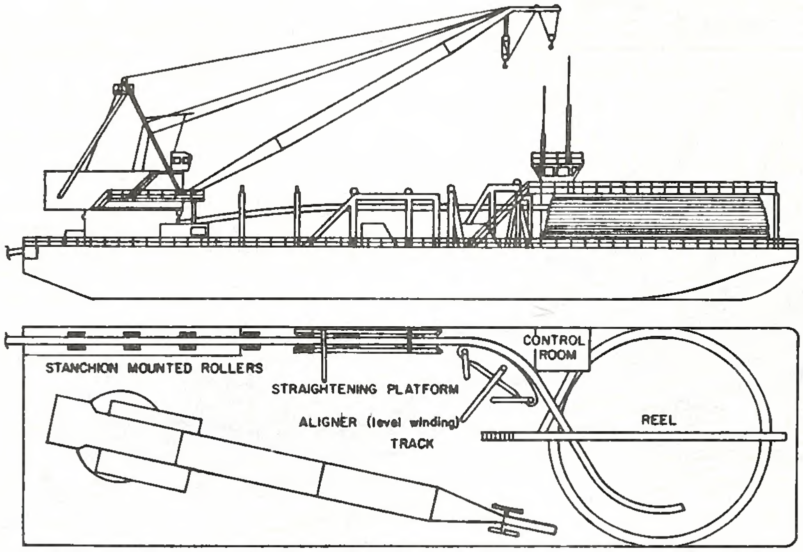
SOURCE: National Academy of Science, Outer Continental Shelf Frontier Technology, p. 125.

and maintenance costs, which vary with the physical characteristics of the route, and (3) the cost of applying for various permits and obtaining the necessary back-up information. Pipeline landfalls and overland routes are usually not located in developed areas. Legal issues and government policies and regulations will also influence route selection.

There are three methods for laying pipelines offshore: (1) the stovepipe method, (2) the reel barge method, and (3) the pull method. The stovepipe method is used for most pipelines and for all large diameter pipelines. Mastic-coated, 40-foot sections of pipe are delivered by a supply vessel from an onshore pipe-coating yard to a lay barge, where they are welded together one at a time and lowered over a "stinger" at the stern of the barge (Figure 21). Each weld is tested with x-ray devices and coated with an anti-corrosive mastic compound or concrete. The stinger and onboard tension equipment help support the pipe and protect it from stress as it extends to the sea floor. During pipelaying operations, the lay barge maintains its position with a series of anchors and winches; the crew winches the lay barge forward and resets some anchors as each new pipe section is welded and lowered overboard.

The reel barge method is used for laying small diameter pipelines (usually 12 inches and less). The method is often used for the smaller "gathering" pipelines which connect platforms to each other and to the main pipeline. The pipe is welded, coated, and tested at an onshore base and wound onto a large spool on a barge (Figure 22). The barge is towed to the pipelaying site, where

Figure 22
Reel Barge

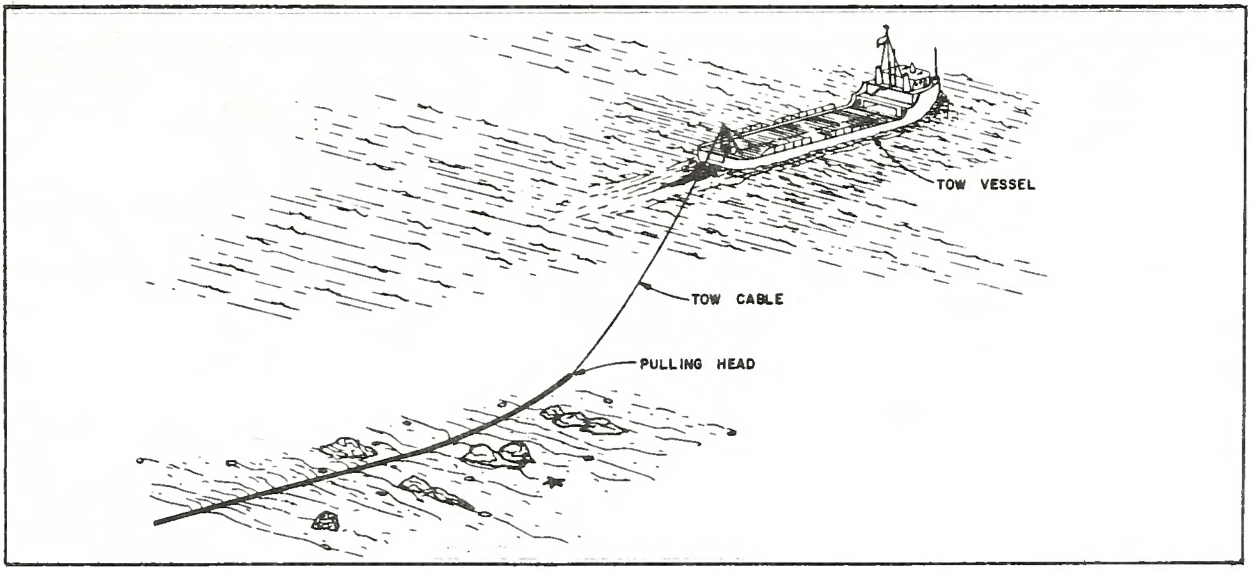


SOURCE: National Academy of Science, Outer Continental Shelf Frontier Technology, p. 125.

the end of the previously laid pipeline section is picked up from the sea floor and welded to the section on the reel. The barge is towed forward to unwind the pipe from the reel. The pipe passes through straightening equipment as it comes off the reel to remove any deformations from coiling. The end of the pipe is capped and lowered to the sea floor. The barge then returns to shore to have the spool refilled. This process continues until the pipeline is completely installed. The reel barge method permits rapid offshore operations but is not practical where concrete coating must be applied to give the pipeline extra weight and strength. The concrete coating cannot withstand the stress of winding and unwinding.

The pull method has three variations; it is not widely used, except for landfall approaches, and has a range limited to two to four miles due to the stress of pulling. In the first variation, sections of pipe are welded together onshore at the landfall and pulled by tugs or lay barges to meet an offshore pipeline that has been laid using either the stovepipe method or the reel barge method (Figure 23). The pipe may also be assembled on a barge near the shore and then pulled to the landfall by onshore winches; this variation is usually used at shore approaches where shallow water inhibits the use of barges.

Figure 23
Bottom Pull Method of Pipeline Installation

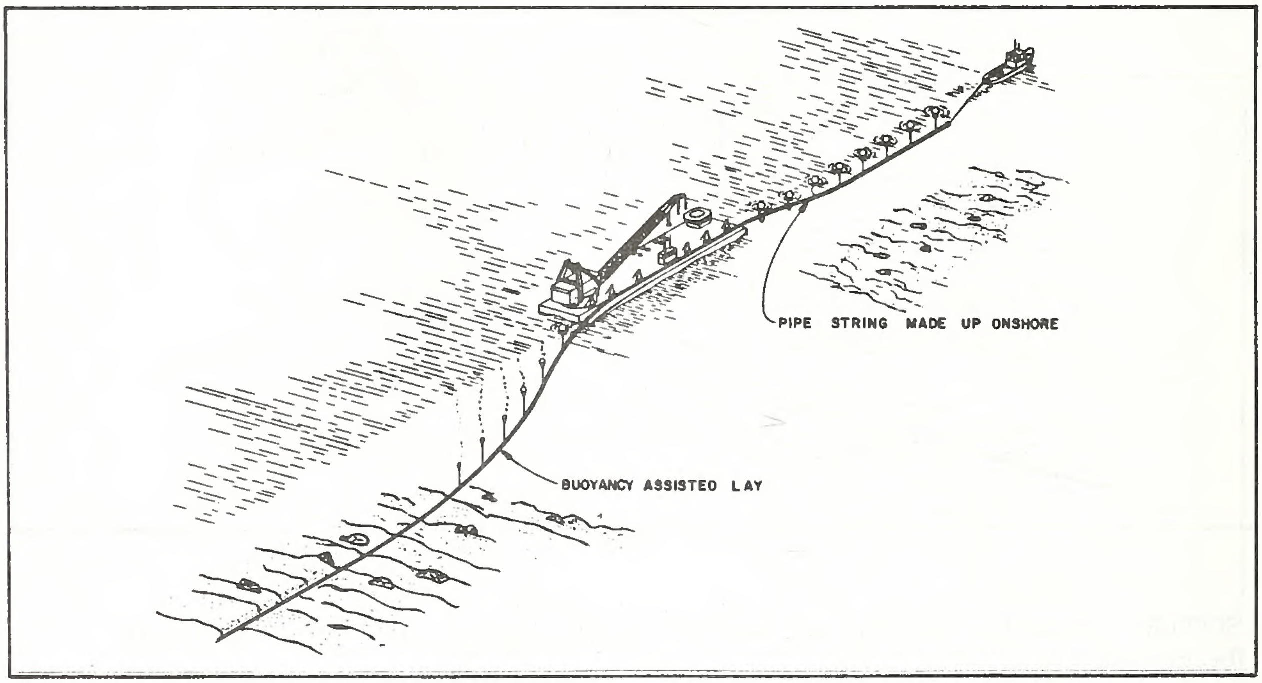


SOURCE: National Academy of Science, Outer Continental Shelf Frontier Technology, p. 130.

A third variation has the pipeline assembled onshore with flotation buoys attached to the line for easier towing (Figure 24); this variation requires calm seas and high-cost during operations.

The "spreads" used to lay pipe consist of a lay barge, one to three tugboats, and two to five supply boats which operate out of pipeline installation support bases. Lay barges range from 200 to 600 feet in length and come in three design categories. Flat-bottom barges are most common because of their economy, spaciousness, stability for supporting heavy equipment, and simplicity of construction. Their shallow draft permits work close to shore. The primary disadvantage of flat-bottom barges is their sensitivity to sea conditions; six to 14-foot waves may shut down operations. Semi-submersible barges are the most expensive to construct and operate, but can operate in 15 to 30-foot waves and avoid costly delays. They are commonly used in areas with frequent adverse weather conditions. Ship-shape barges have hulls shaped like those of ships and are often self-propelled (reducing the number of tugs needed). Their relatively deep draft keeps them from operating near the shore. Tugboats pull the barges along as each new section of pipe is laid. Two or three supply boats are required to keep the barge supplied with pipe from a pipe-coating yard. Under good weather conditions, the barge crew can lay over a mile of pipe each day.

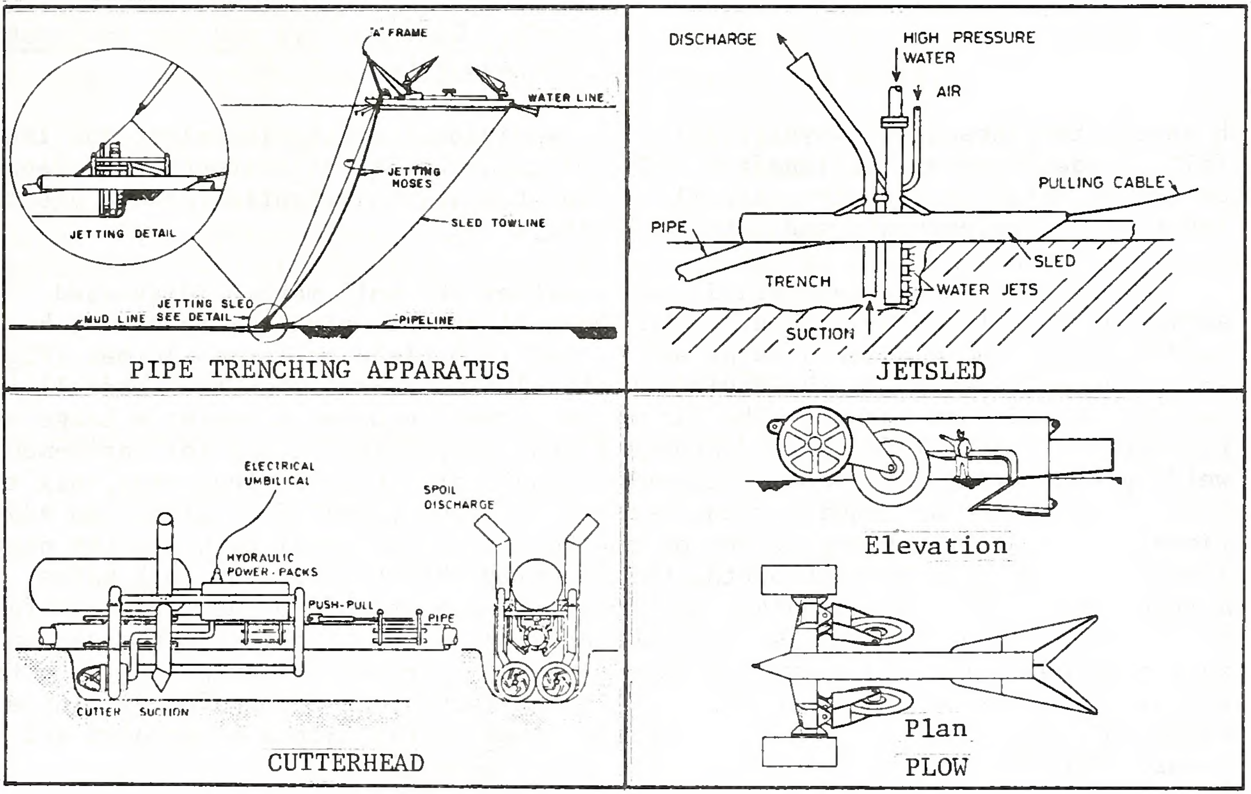
Figure 24
Flotation Method of Pipeline Installation



SOURCE: National Academy of Science, Outer Continental Shelf Frontier Technology, p. 120.

Pipelines may be trenched and buried for greater stability and to protect them from currents, anchors, and commercial fishing trawlers. Current Interior Department guidelines require the burial of pipelines when the water depth is less than 200 feet. There are three types of trenching machines, each of which is pulled by a specially-equipped "bury barge" (Figure 25). Cutterhead trenchers are machines with rotating heads which cut through sediments. Jet sled trenchers use high-pressure jets of water. Cutterheads and jet sleds are lowered from the bury barge and placed over the pipeline, which settles into the trench as it is being dug. Sediments removed by the machines are sucked through pipes and discharged above and to the sides of the trench. Plow-type trenchers dig a trench before the pipe is laid. They tend to be used for landfall approaches, where the pipeline is constructed onshore or offshore, towed along the route, and sunk into the trench. Natural currents and wave action are generally relied upon to refill trenches once a pipeline has been laid. Pipeline burial is not always necessary in deeper waters;

Figure 25
Pipeline Trenching Equipment



PIPE TRENCHING APPARATUS

JETSLED

CUTTERHEAD

PLOW

SOURCE: National Academy of Science, Outer Continental Shelf Frontier Technology, p. 132, and Gowen et al., Choosing Offshore Pipeline Routes, pp. 21-22.

Figure 26
Pipelaying at the Landfall

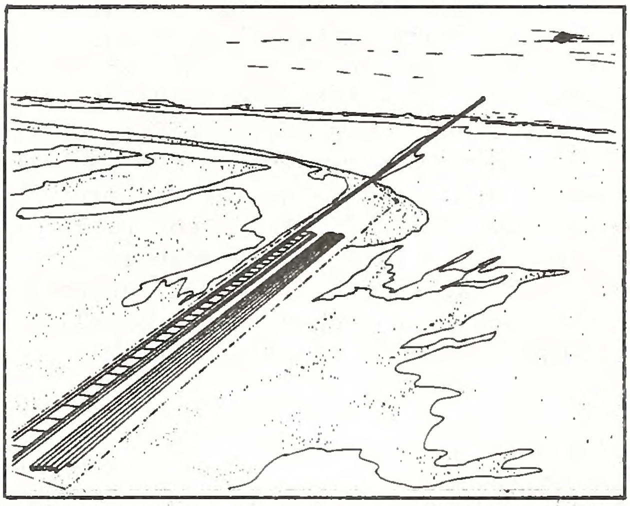
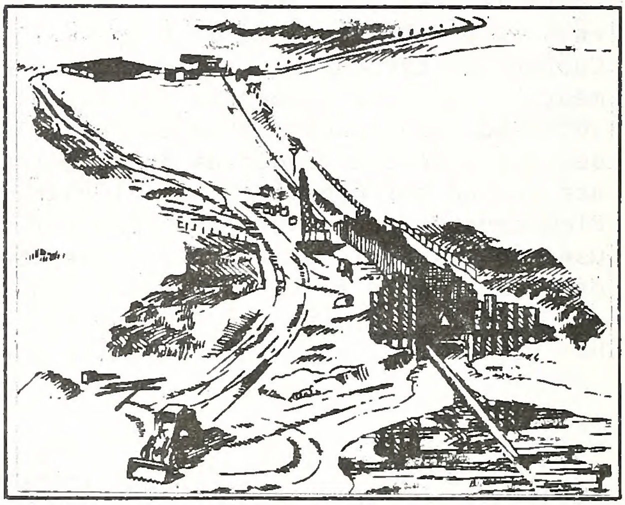


Figure 27
Trench Lined with Sheet Piling at the Landfall



SOURCE: Gillman, Oil and Gas in Coastal Lands and Waters, p. 82.

however, trenches are always refilled for additional protection along the landfall approach and at the landfall. The width and depth of a trench will depend on the diameter of the pipe, sea floor conditions, and potential damage agents (such as strong currents and bottom fishing).

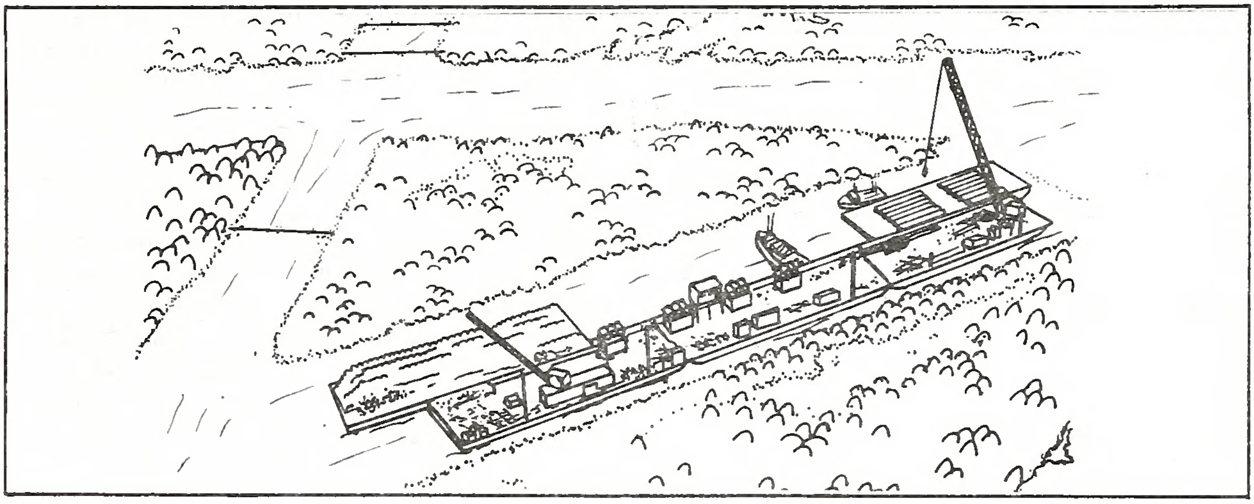
Pipelaying at the landfall involves either the pull method (discussed above) or the flotation method. With the pull method, pipe sections will be welded on the shore or on a barge and pulled into place by large winches (Figure 26). The pull method is the basic installation technique when the landfall is a sand beach and dune system. The flotation method requires dredging a large canal through the landfall for some distance inland to provide access for barge-mounted welding and laying equipment. Flotation canals are 40 to 50 feet wide, six to eight feet deep, and require rights-of-way from 300 to 450 feet wide. An additional, smaller trench may be dug on the bottom of the canal to house the pipeline, which is laid by flat-bottom barges using the stovepipe or reel barge method. The flotation technique is typically used at soft or unstable landfalls where heavy land-based equipment cannot operate, such as salt marshes, and on vary shallow shorelines where lay barges cannot operate. Sheet piling is often used to line the trench at the landfall installation; it allows for digging a deep and narrow trench without having the sides of the trench slump down and inward (Figure 27).

A variety of pipelaying techniques is used inland from the landfall depending on the characteristics of the land along the pipeline route. Pipeline installations in wetlands involve either the flotation method (discussed above) or the push method. With the push method, a ditch four to six feet wide and eight feet deep is excavated by a marsh buggy (an amphibious vehicle which travels on pontoons and tractor treads). Pipe sections are welded together at a station on firm land or on a lay barge (Figure 28). Floats are strapped to the pipe, which is then slowly pushed through the ditch from the welding stations. The floats are cut away after the pipeline is in position; the line settles to the bottom of the ditch. The ditch is usually refilled with the dredge spoil deposited beside it by the marsh buggy. Pipeline sections up to 15 miles long have been installed using the push method. The push method usually requires a right-of-way 150 feet wide.

On firm land, pipeline construction is similar to other upland construction for power transmission lines and water and sewer lines. The pipeline will usually be buried at a depth of four to six feet. Inland pipeline construction will require a right-of-way from 50 to 75 feet wide and follow the shortest possible route from the landfall to the gas processing plant, oil refinery, or marine terminal. The right-of-way may be wider at places to accommodate pressure booster stations and partial processing facilities. Where necessary, the pipeline will be tunneled under roads and railroad tracks and may span or be submerged under rivers and lakes.

Pipelaying companies make a strong effort to return the land along the pipeline route to its natural condition after installation is complete. The degree to which full restoration occurs depends on the sensitivity of the affected ecosystem, future uses of the landfall and pipeline right-of-way, government regulations, and stipulations included in right-of-way negotiations.

Figure 28
Pipelaying in Wetlands



The main concern with beach and dune restoration is to return the shoreline to its natural protective function, sheltering back dunes, wetlands, and other ecosystems from wave erosion and salt water inundation. The first step in restoration is refilling the trench with sand and possibly crushed rock, sand fence, or some other material to stabilize the trench and protect the pipeline from future erosion. After the trench is refilled, the beach and dunes are returned to their original contours and revegetated. Contouring may be aided by artificial stabilization techniques, such as placing solid masses (sand fence, etc.) inside the dune or covering the dunes with netting, thatch, or sand fences until vegetation firmly reestablishes itself. Artificial reseeding and replanting ensure long-term stability of the dune system. In addition to restoring contours and vegetation, temporary paths and construction debris should be removed by the contractor to the greatest extent possible.

The unique structure and function of wetlands, based on their loose, highly-saturated sediment structure and drainage patterns, make them the most difficult environments to restore. Restoration attempts in wetlands tend to arise from governmental regulations or right-of-way negotiations rather than the industry's desire to protect the pipeline from damage. Wetland restorations seek to minimize the impacts of construction on natural environmental functions; the full return of the aesthetic quality of wetlands cannot be expected. As a first step, the contractor should remove all pipe floats and other construction debris. Completely refilling the trench is usually not possible, especially in very soft sediments, because evaporation and subsidence significantly reduce the volume of the spoil left from trench excavation. Even after refilling, a shallow path of water may be seen above the pipeline. A higher volume of refill will occur in areas with firmer sediments. Spoil banks along canals and trenches may be cut at frequent intervals so they do not interrupt the wetland's natural drainage patterns. Landowners or government agencies may require the contractor to plug pipeline canals with small dams where the canals intersect existing waterways. The plugs are permanent structures made of heavy or impervious material, such as shell or clay, with a rock cap. Plugs prohibit boat traffic in the canal (to prevent erosion of the canal's sides) and prevent alterations in natural drainage patterns. Revegetation is usually not attempted in wetland restorations; the native vegetation may or may not colonize the disturbed area.

After the pipeline is completed, it is pressure-tested to reveal potential leaks or other structural problems. Submarine photography may detect exterior damage to the pipeline and potentially harmful sea floor conditions. Once the pipeline is in operation, it is continuously monitored by pressure sensors and flow indicators which detect leaks and other flow reductions. Pipelines and pumping equipment are controlled by radio equipment, based at a platform or onshore facility, which can immediately cut off the flow to any part of the line which may be leaking. Federal regulations require surface vessels and aircraft to patrol the offshore pipeline route every two weeks; this helps spot leaks which pressure monitors do not detect. The

U.S. Department of Transportation's Office of Pipeline Safety inspects each pipeline annually. The elements of these annual inspections vary from one pipeline system to another and depend on the system's particular operating conditions and its performance in previous inspections. Special inspections occur when certain natural or human activities, such as earthquakes or pipeline alterations, may impair the line's structural integrity. Pipeline construction companies, oil companies, and gas transmission companies have their own inspection programs to check the system more carefully or to check components not subject to government inspections.

Impacts on the Local Economy

Pipelines generate significant employment during their construction but very little during their operation. A lay barge employs about 200 people. A bury barge employs about 35 people. Tug boats and supply vessels each require five or six crew members (NERBC, Factbook, p. 3.34). Each lay barge requires one to three tugs and two to five supply vessels. Local labor may constitute as little as 20 percent of the installation workforce due to the short-term nature of the job and the need for large numbers of welders and other specialized workers. Most of the crew may be contracted with the pipelaying vessels from outside the frontier region.

Once the pipeline system is in place, its operations are highly automated and controlled by the platform crew or workers at an onshore base. An onshore pumping station empoys about 17 people, three-fourths of which may be hired locally (NERBC, Factbook p. 3.35).

The offshore pipeline system may interfere with commercial fishing activity by limiting access to fishing grounds and damaging bottom-fishing gear. Gathering pipelines and main pipelines may present barriers to commercial fishing, "dividing lines" over which a bottom-fishing vessel will not pass to avoid damage to the pipeline and to fishing gear. Unburied lines in the production area and the safety zones established around platforms may prohibit fishing in pipeline rights-of-way and the waters between platforms. Even trawling over buried pipelines may not be advisable since buried lines are sometimes re-exposed by underwater currents. Pipeline route selection should consider the location of major fishing areas, the trawling patterns of fishing vessels, and the extent to which the pipeline system will block access. Exposed pipelines and bottom debris left by pipeline trenching and installation may cause the loss of or damage to trawling gear. The risk of damage is greater when the pipeline is trenched but not buried than when the pipeline is laying directly on the ocean bottom; in both cases, trawling gear will usually unhook rather than be lost. Gear damage is more likely to result from bottom debris (bottom materials dug up during trenching, debris from pipelaying vessels and equipment, and stone pipeline covers). Minimizing damage to fishing gear requires engineering solutions as well as wise routing.

Onshore and nearshore pipeline installation, especially at the landfall, may conflict with recreation and commercial fishing on the shoreline, in estuarine waters, and in other areas. Since the pipeline will probably be buried and significant disruption occurs only during construction, these problems may be avoided by installing the pipeline in seasons with minimal recreational and fishing activity.

Impacts on Natural Resources

Pipeline Installation -- The threat to natural resources from the pipeline system is greater during its installation than during its operation. Offshore and onshore environmental impacts may be minimized by (1) choosing a site which has the fewest constraints to pipeline installation and (2) using appropriate installation and site restoration techniques.

Offshore environmental impacts will be less significant than onshore environmental impacts. The predominant offshore effects result from pipeline trenching and burial, which may displace bottom habitats, increase turbidity along the installation route, and cause chemical changes in the water column. Effects are minimal when the pipeline is simply laid on the sea floor rather than trenched. The route selection process should avoid unique or sensitive bottom habitats wherever possible. Previous studies indicate that pipeline installation creates less of a sediment disturbance to offshore environments than do other marine activities, such as trawling and mollusk dredging (Gowen et al., Choosing Offshore Pipeline Routes, p. 27). Whereas pipeline installation creates a one-time disturbance, these other activities recur from one year to the next and can affect a larger bottom area.

The severity of onshore environmental impacts arising from pipeline installation depends on site characteristics along the pipeline route. On firm upland sites and non-eroding landfalls, significant erosion will not occur and habitat impacts will remain localized if the site is restored to its initial condition. Installation creates potentially greater impacts in wetlands, estuarine waters, and eroding shorelines. The shore approach and landfall require special care because of the sensitivity of the land-water interface; pipeline installation may affect nearby beach erosion and accretion patterns. Installation in wetlands may affect the water-holding capacity of wetland soils and alter large-scale drainage and nutrient transportation patterns (either blocking or shifting drainage or connecting separate aquatic environments). Where possible, the pipeline route should avoid eroding shorelines and sensitive ecosystems.

To minimize the impacts of pipeline installation and to ensure that impacts do not occur after installation, pipeline companies should (1) schedule installation to avoid key ecological seasons, (2) minimize the affected surface area, (3) immediately restore the land-water interface, and (4) restore the entire affected area to its natural state. Avoiding fish and bird migration and breeding seasons (spring and summer) may conflict with scheduling pipeline installation to avoid seasons with more hazardous weather conditions (fall and winter). Minimizing the affected surface area may be accomplished by limiting construction vehicle access and materials storage to well-defined corridors. This method is valuable in fragile ecosystems which will recover slowly; it may not be necessary in more stable areas which exhibit a faster rate of natural recovery. When installation occurs in estuarine environments, a silt curtain surrounding the construction site will inhibit the flow of sediments over a large area. Immediately restoring the landfall is especially important in dynamic shorelines, where tides and waves may damage an exposed pipeline or damage important landward ecosystems (dunes, wetlands, etc.) which are protected by the beach.

Pipeline Operation -- Once the pipeline system is in operation, its impacts will be minimal, except if an oil spill occurs. Small quantities of hydrocarbon gasses, sulfur oxides, and nitrogen oxides will be released into the air from compressors, pumping stations, valves, and seals along the pipeline route. Compressors, unless equipped with silencers, will continously generate noise audible beyond a one-mile radius (NERBC, Factbook, p. 3.45). The aesthetic impact of the pipeline depends on site restoration practices used during its installation; the aesthetic impact of the pipeline may be less significant than that of onshore facilities located along the line (gas processing plants, pumping stations, etc.). There are no significant solid wastes associated with normal pipeline operations.

Oil spills resulting from pipeline failure, though of low probability, can have serious widespread impacts on the natural environment. Releases of natural gas into the air and water have no significant environmental impacts. Pipeline systems have a lower oil spill risk than transporting oil to shore with tankers. The potential sources of pipeline failure include: (1) internal and external corrosion, (3) damage from anchors, fishing nets, and other equipment, (3) defective pipe seams, valves, or other pumping equipment, (4) improper operation, and (5) stressful geological conditions (offshore mudslides, earthquakes, etc.). Pipeline coating and quality control measures are much better than those of 20 years ago. Pipeline operations are continuously monitored, with valves at each end capable of immediately shutting off the flow of oil. Pipelines are periodically inspected for leaks and other damage. Table 4 shows the cause, number, and volume of oil spills (releasing 50 barrels or more) resulting from pipeline accidents in 1972. Of the 75 spills caused by external corrosion, only one involved a pipeline constructed after 1960 (NERBC, Factbook, pp. 3.39-3.40). Chronic low-level leakages from pipe seams, valves, and other sources may occur during pipeline operation. Such site-specific characteristics as water mixing and flushing rates and the tolerance level of local organisms will determine the severity of the impact of low-level leaks. There is little information on the extent of impacts from continuous hydrocarbon concentrations in aquatic environments.

Table 4
Oil Pipeline Accidents - 1972
(from Office of Pipeline Safety data)

Cause	Number	Percent of Total	Size of Spill (Barrels)
External corrosion	75	24.4	40,475
Equipment rupturing line	69	22.3	83,592
Defective pipe seam	28	9.1	43,303
Internal corrosion	25	8.1	38,988
Improper operation	22	7.1	45,885
Miscellaneous (18 other causes)	90	29.0	108,411

Pipe Coating Yards

When the offshore industry decides to build a marine pipeline, the pipeline owner will contract the services of a pipe coating yard. The yard applies mastic and concrete coatings to protect the steel pipe from sea water corrosion and underwater damage and to add enough weight to overcome the buoyancy of oil and gas.

Forty-foot pipe sections are delivered by rail or barge from a steel mill to the coating yard. Forklifts and trucks move the pipe from the yard's storage area to its processing station. The pipe sections first enter a cleaning station where they are baked, sand-blasted or shot-blasted (with small steel particles), and air-blasted to remove all moisture, mill scale, rust, and other foreign substances. After cleaning, the pipe sections are primed with a thin coat of asphalt and petroleum-based thinner. The yard crew then coats the outside of each 40-foot section with a dense, seamless mastic compound to inhibit corrosion. This compound consists, by weight, of ten to 12 percent asphalt, 88 to 90 percent sand and crushed stone, and less than one percent fiberglass; it is mixed at the yard by heating the asphalt and carefully adding the other materials. Hot mastic is extended over the primed pipe in a thick, uniform coating, which fuses into the primer coat, cools, and forms a firm bond. Other anti-corrosion and insulated coatings may be applied in addition to the mastic. The crew then sprays the pipe with water and coats the outside with hydrated lime to further cool the pipe and keep it from sticking to other sections during storage. The pipe sections are laid in single layers until the mastic coating hardens. The coating is trimmed to reveal several inches of bare pipe at each end so the sections can be welded aboard the lay barge. After trimming, each section is inspected, patched (if necessary), and stacked in the yard's storage area. The yard crew exercises care to not damage the coating while moving pipe sections from one part of the yard to another.

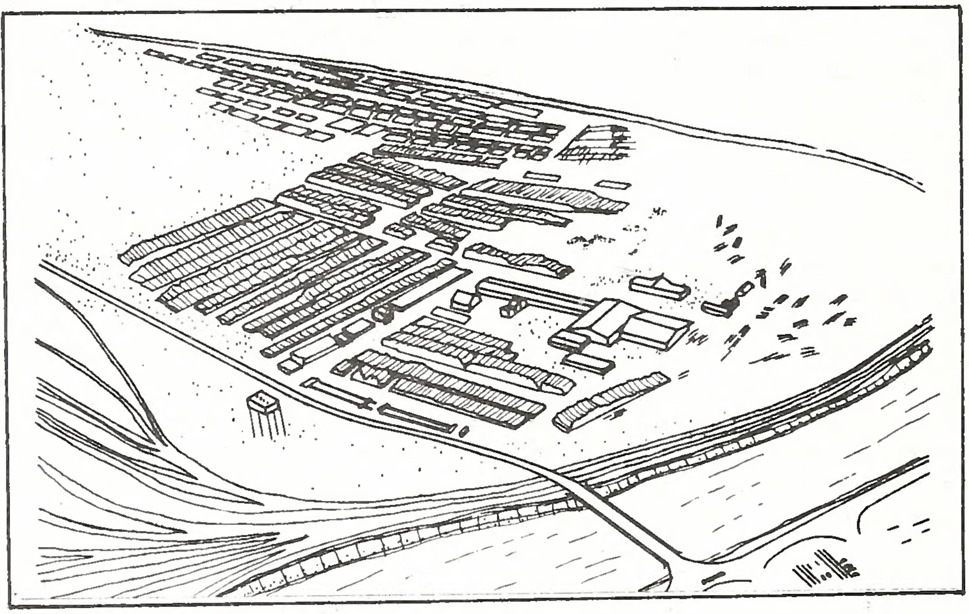
In addition to the mastic coating, the yard crew may coat the exterior of pipe sections with concrete to weigh down the pipeline and protect it from any impacts during and after pipelaying operations. At the concrete coating station, each pipe section is rotated and coated with concrete and galvanized wire mesh. Sand and iron ore aggregates added to the concrete provide a high density coating. The densest mixture is, by weight, 84 percent iron ore and 16 percent Portland cement; the least dense mixture is 80 percent sand and 20 percent Portland cement (NERBC, Factbook, p. 9.10). The concrete's composition and the coating's thickness will depend on the requirements of the pipeline company.

After applying the concrete, the yard crew trims the wire mesh and sprays the pipe section with a curing substance. The sections are stacked in the storage area after the concrete has cured for about four days; complete curing takes about one month. Each pipe section is thoroughly inspected before it is loaded by crane onto a supply barge and transported offshore to the lay barge. A completely coated 40-foot pipe section may weigh from 3,000 pounds (14-inch diameter) to 40,000 pounds (42-inch diameter) (NERBC, Factbook, p. 9.5).

There are two types of pipe coating operations: portable and permanent. A portable or "railhead" operation may be set up by the pipe coating company if the offshore demand for pipe is small or short-lived. Portable operations can coat all sizes of pipe. The pipe coating company is likely to set up a permanent yard when it receives a long-term contract in the region or can capture a large enough portion of the offshore market to justify the initial capital investment.

A permanent yard occupies 75 to 200 acres (Figure 29); a portable operation occupies about 30 acres. Up to 95 percent of the yard will be used for storing stacks of uncoated and finished pipe. Up to 300 miles of pipe may be stored at a 100-acre yard, depending on the diameter of the pipe being coated. The yard also requires storage space for iron ore, sand, lime, fiberglass, wire mesh, and other materials, with 40,000 to 80,000 tons stored at one time (NERBC, Factbook, p. 9.4). Buildings on the site will house cleaning and coating stations, equipment, supplies, maintenance services, and administrative offices. The site will probably have a rail terminal, marine terminal,

Figure 29
Pipe Coating Yard



and loading stations. The total land area required by the yard will depend on the amount of pipe which must be coated and the life expectancy of offshore pipeline installations.

The yard site should be level, well-drained, and have a low water table. The land must also have a high load-bearing capacity due to the weight of the pipe sections, raw materials, machinery, and moving equipment involved in pipe coating operations. The yard must be located at the waterfront and preferably have access to a railway. Pipe sections will be shipped from the steel mill on barges or railroad cars. Sand, cement, and iron ore may be shipped to the yard by boat, rail, or truck. Other materials (mastic, wire mesh, equipment, etc.) are usually delivered by truck. The yard must have access to at least 750 feet of wharf frontage to load two supply barges simultaneously, with a minimum channel depth of ten feet for barges and up to 30 feet for other vessels.

Proximity to offshore activity and to other onshore oil and gas facilities also influences the location of a pipe coating yard. Nearby service bases or pipeline installation support bases provide a base of operations for workboats and allow the pipe coating company to maintain close contact with the pipelaying company and oil and gas companies.

A pipe coating company usually decides on the location of a new yard after being awarded a contract by the pipeline owner. However, the company may negotiate land options before receiving a contract if the leasing region contains many tracts and petroleum companies and sizable capital expenditures for leases and exploration. Once the yard is developed, its level of activity will depend on the total length of the offshore pipeline system and the timing of pipelaying operations.

The factors influencing the decision to establish a new coating yard in a frontier region include (1) existing yards elsewhere in the region, (2) the ability of existing yards to meet offshore demands, and (3) whether subsequent lease sales are expected in the region.

Impacts on the Local Economy

The labor requirements of pipe coating yards vary with the capacity of the yard and the duration of offshore pipelaying operations. The business is characterized by "boom-bust" fluctuations in activity and yard employment which depend on the demand for coated pipe in the region. Pipe coating is a seasonal activity, geared to the seasonality of pipelaying operations as well as to contracts with pipeline companies. Coating and laying operations usually occur from April to November to avoid adverse weather conditions. Coating operations begin about six weeks prior to pipelaying operations. Existing pipe coating yards along the Gulf coast employ from 100 to 200 workers during peak activity and 40 to 85 workers during slack periods (NERBC, Factbook, p. 9.23). However, if no continuous demand exists for marine pipe in the frontier region (as there is off the Gulf coast), the yard is likely to shut down completely once the field goes into production.

The summer-oriented pipe coating and installation season may create conflicts with recreation and commercial fishing on coastal land and waters. The existence of these conflicts will depend primarily on the location of the pipe coating yard and the level of vessel traffic it generates.

Impacts on Natural Resources

As with labor requirements, the yard's impact on the local environment will depend on offshore demands, the yard's level of activity, and the yard's size.

Site Preparation -- There may have to be considerable grading, filling, clearing, and channel dredging in setting up a pipe coating yard, depending on the initial condition of the site. Wetlands or other "soft" spots must be removed and replaced with sand or gravel to provide the necessary load-bearing strength. In addition to displacing natural habitats, site preparation may promote erosion and sedimentation by baring and compacting soil and increasing runoff. Channel dredging will disturb aquatic organisms by stirring up sediments and any hazardous substances they contain; dredge spoil will be deposited on land or in coastal waters. Channel dredging may also alter water circulation and erosion patterns. As for other onshore facilities, these impacts will be minimal if the pipe coating yard locates at a vacant waterfront site which is already developed and has access to a navigable channel.

Water requirements -- The pipe coating yard will require from 3,000 to 15,000 gallons of water each day for mixing concrete, cooling and cleaning pipe sections, and other purposes (NERBC, Factbook, p. 9.18).

Wastewater -- Discharges from a pipe coating yard include process water, cooling water, domestic sewage, and site runoff. Process water used to clean the pipe and to mix concrete and hydrated lime contains hydrocarbons, alkaline compounds, and suspended solids. Most process water is recycled. The use of settling basins and other treatment methods can minimize the amount of solids and chemical compounds which are discharged by the yard. The water which cools the pipe after the application of mastic coatings may wash metal fragments and other particulate matter into adjacent waters as well as increase their temperature; settling and cooling systems can minimize these problems. The volume of domestic sewage discharged by the yard will depend on the number of workers; the sewage will be handled by an existing municipal treatment system or an on-site treatment facility. Runoff from the yard may contain heavy metals, soluble inorganic and organic chemicals, and particulate matter from the routine operation of the yard and occasional spills and leaks of process chemicals. If the company keeps the site clean and responds quickly to accidental spills, runoff water will not significantly contaminate adjacent coastal waters.

Air Emissions -- Air pollutants at the yard will come from two sources: (1) the cleaning and coating process and (2) fuel combustion. The sand or metal particles used to shot-blast pipe sections may be released into the air along with particles abraded from pipe surfaces. Dry sand and cement are released into the air as they are pneumatically blown into receiving bins and concrete mixers. The shot-blasting and concrete mixing processes normally entail the use of filters or some other dust collection device to reclaim raw materials and minimize particulate emissions from the yard. Dirt roads, sand piles, and the occasional breakage of a bag of cement will contribute low levels of dust at the site. The combustion of fuel oil, natural gas, diesel fuel, and other fuels by the yard's boilers, compressors, cranes, and trucks, will release hydrocarbons, nitrogen oxides, sulfur oxides, carbon monoxide, and particulates into the air. The yard may contain up to 50 cranes, trucks, and forklifts. The level of these combustion emissions will depend on the level of activity at the yard and the types of fuel it uses; these emissions may be controlled by various techniques.

Solid Waste -- A pipe coating yard must dispose of packing materials, concrete and mastic fragments, scrap metal, and contaminated debris. Packing materials consist of various non-hazardous wood and paper items which may be incinerated or buried at a local landfill. Trimmed concrete fragments and spilled sand and cement are typically used to improve roadbeds at and near the yard. Trimmed mastic fragments are melted down and recycled. Leftover wire mesh, cables, strapping, and drums are frequently sold as scrap metal. Some materials and containers may be contaminated with hazardous substances. This debris must be properly treated, incinerated, or buried in a special landfill to prevent contamination of the water and air.

Noise -- Shot-blasting, boilers, compressors, cranes, and trucks create high noise levels at the site, from 75 to 105 decibels (NERBC, Factbook, p. 9.32). Pipe coating yards often enclose machinery in buildings and install mufflers on all equipment to protect workers as well as users of adjacent land. Vegetative buffers can also reduce the amount of sound which travels from the yard.

Aesthetics -- Aesthetic impacts depend on the location of the yard and the nature of surrounding land and water uses. Pipe coating yards do not operate 24 hours a day; work occurs in one or two eight-hour shifts, varying with the demands of offshore pipelaying operations.

Platform and Pipeline Installation Support Bases

Once they receive contracts from oil and gas companies, platform installation companies and pipelaying companies establish separate bases to supply and service the vessels and crews involved in their offshore operations. Each base can support several pipelaying operations or platform installations at one time. These bases are usually temporary and set up on leased waterfront land; a company may set up a more permanent facility if it anticipates a continuous long-term demand for its services in the leasing region. The installation company may try to operate out of an oil company's permanent service base, even though permanent service bases rarely have the extra space available. Installation support bases therefore tend to locate elsewhere, sometimes in the same port as the permanent service base. Distance to offshore operations is the key criterion in locating an installation base.

A support base requires about five acres of land to support one pipelaying operation or up to four platform installations per year. Open storage occupies most of the site, with one acre set aside for a helicopter pad and offices. A base supporting pipelaying operations may include equipment storage warehouses. Pipe sections are stored at the pipe coating yard, not at the installation base.

An installation support base requires at least 200 feet of wharf frontage, with a minimum water depth of 15 to 20 feet, for each "spread" of vessels operating offshore. Installation companies prefer locating along a channel at least five times wider than a standard lay barge or derrick barge to permit the safe and easy maneuvering of barges, tugs, and supply and crew vessels. The base must have highway or rail access for transporting fuel, welding equipment, and other supplies. Helicopters carry crews and special materials to offshore installation sites; helicopters are used to change crews more frequently than boats when operations are conducted more than 150 miles from shore (NERBC, Factbook, p. 1.46).

Impacts on the Local Economy

An installation support base employs roughly 25 workers to staff wharf, warehouse, office, and helicopter operations. About half of the workers will be recruited from the local labor force. The base exhibits the same "boom-bust" characteristics as a pipe coating yard due to the short-term nature of platform and pipeline installations, which usually take from three to twelve months. The yard will shut down if there is not continuous demand for its services offshore.

Impacts on Natural Resources

The environmental impacts of an installation support base are minimal. Site preparation will have practically no impact if the base sets up at existing port facilities; otherwise, land must be cleared and bulkheaded, and a channel may have to be dredged. An installation support base has no significant water supply requirements and processes no large quantities of solid waste. Air emissions (from fuel storage and combustion) and wastewater discharges will be similar to those at a temporary service base. Noise and aesthetic impacts will depend on the location of the base, whether it operates 24 hours a day, and the types of equipment it houses (cranes, trucks, etc.).

Partial Processing Facilities

Partial processing facilities remove impurities from the natural gas and crude oil stream which comes out of the well. The well stream consists of oil, gas, and formation water (containing brine, dissolved solids, and suspended solids). Partial processing reduces the water and sediment content of the oil stream to about one percent and separates crude oil from natural gas. The gas and oil are then delivered to gas processing plants and oil refineries for final processing and conversion into a range of products. Partial processing facilities are individually designed to meet the needs of a particular well stream and resemble a small refinery, with various pipes, separation and treatment tanks, and storage tanks. Partial processing may occur onshore or offshore; the location and design of a facility are determined at the same time as platform installation and transportation decisions.

Partial processing facilities perform three functions: (1) gas separation, (2) oil-water separation, and (3) formation water treatment and oil recovery. Gas separation is the first step in processing the well stream. Due to formation pressures, natural gas and formation water will be suspended in the crude oil and must be separated from the rest of the well stream for final processing. To release natural gas, the well stream passes through a two-phase or three-phase series of separation vessels with progressively lower pressures. Two-phase separators separate natural gas, crude oil (containing emulsified formation water), and free formation water. The components of the well stream separate by gravity in each separation vessel and are drawn off by valves located at the appropriate height. After separation, natural gas is either delivered to shore, pumped back into the hydrocarbon reservoir, or used to fuel equipment on the platform. Gas separation usually occurs on offshore platforms.

Oil-water separation removes free water and emulsified water from the crude oil stream. Free water is removed by a three-phase separator or a free water knockout drum (which also relies on gravity and controlled pressure). The free water is treated before it is discharged; the rest of the well stream is piped to further processing facilities. The equipment for separating free water is simple and usually set up on offshore platforms. Separating emulsion water from crude oil is more complex and is usually done onshore. Emulsified water is removed by applying heat, electrostatic action, and chemical action to the crude oil stream; these methods are more of a safety hazard than the separation methods discussed previously.

Free water and emulsion water still contain significant amounts of oil after they are separated from the rest of the well stream. Water treatment methods recover this oil and make the water suitable for discharge. Water treatment equipment includes gravity separators, oil skimmers, gas flotation chambers, coalescers, and filters. Gravity separators and oil skimmers rely on the density differential between oil and water and draw oil off the top of the water surface. Both methods require large containers and long retention periods. Gas flotation chambers mix gas-saturated "clean" water with the emulsified oil-water stream. The gas bubbles expand and carry oil particles upwards, where the oil can be skimmed off the water surface. Some of the remaining water is treated and discharged; the rest is resaturated with gas in a high-pressure environment. Coalescers use a system of tile plates as a base to which oil particles adhere. The oil particles are then isolated and collected by a graded filtration bed. Oil-water separation filters employ either fibrous media or loose granular media. Fibrous filters usually come as replaceable cartridges containing fiberglass or some other fibrous medium. Loose media filters normally use a bed of sand, gravel, or crushed coal to separate oil, emulsified water, and suspended solids.

After separation, the gas is delivered to onshore processing facilities, the oil is delivered to onshore refineries, and the water is piped to a brine treatment system. The brine treatment system removes remaining solids and oil from the water. The water is then piped to a storage tank and eventually pumped into a deep injection well or discharged into the ocean or coastal waters.

The decision regarding how much partial processing occurs onshore and how much offshore is made at the same time as platform installation decisions and transportation decisions (pipelines v. tankers). There is a general tendency to locate the simpler, preliminary operations (gas separation and free water removal) offshore and to locate emulsion separation operations onshore (due to their greater space needs and greater safety risks). If the entire well stream is pumped to shore, the water and suspended solids contained in the stream will reduce pipeline efficiency and require a larger, more expensive pipeline to carry the same amount of gas and crude oil to shore. Such a strategy will, however, reduce space requirements on offshore platforms. Offshore processing creates a demand for larger platforms or additional platforms to house separation equipment and personnel; emulsion separation activities, when conducted offshore, are usually housed for safety reasons on their own platforms or barges. If tankers and barges, rather than pipelines, deliver crude oil to shore, all partial processing will probably occur offshore.

The decision on which processing facilities locate onshore and offshore involves a tradeoff between platform costs and pipeline costs and efficiency. The farther the oil and gas field is from shore, the greater is the tendency to locate partial processing facilities offshore; pipeline costs increase with distance while the cost of additional platform space is relatively insensitive to distance. There will be an incentive to perform some processing offshore if the well stream contains a high percentage of water and suspended solids (which decreases pipeline efficiency and increases pipeline costs). There will be an incentive to perform some processing onshore if the well stream contains a high percentage of oil-water emulsions (since emulsion separation requires separate platforms when conducted offshore). If the offshore field produces significant quantities of both oil and gas, companies may decide to pipe the entire well stream to shore for processing via a single, large pipeline rather than construct offshore processing facilities and two smaller pipelines (one for oil, one for gas).

The location of onshore partial processing facilities is influenced by the location of pipeline landfalls, overland pipelines, marine terminals, refineries, and gas processing plants. Partial processing facilities tend to locate along pipeline landfalls and overland pipelines to minimize the cost of constructing branch lines from the pipeline to the processing facility. Partial processing facilities also tend to locate near the shoreline, though the key determinant here is the cost and availability of land along the pipeline route. The locations of marine terminals, refineries, and gas processing plants influence the location of partial processing plants by influencing the location of the pipeline route. If a partial processing facility already exists in the area to handle another well stream and has surplus capacity, oil and gas companies may direct the well stream to it rather than build a new facility; opportunities for this will be limited if the two well streams have different chemical and physical properties and require different treatment methods. An onshore partial processing facility requires about 15 acres of land per 100,000 barrels of oil and gas processed, if the facility includes gas separation. If gas separation is performed offshore, an onshore facility requires less than ten acres of land. The facility site should have highway access; certain oil and gas products separated and stored at the facility may be transported away by tank trucks. A waterfront site is not necessary.

An onshore partial processing facility may locate at a marine terminal or gas processing plant, rather than at a separate site, depending on the location of existing facilities, land availability at existing facilities and the ownership of natural gas coming from the well. A partial processing facility is likely to locate at or near a marine terminal if marine terminals are part of the offshore oil transportation strategy. The location of a partial processing facility at a gas processing plant will be influenced by gas ownership patterns. Natural gas is often separated and sold to a gas transmission company at the production platform; in this case, the gas transmission company will simply pipe the gas ashore to a gas processing plant. An offshore oil company will sometimes not sell the gas offshore, electing to bring it ashore to sell it; in this case, the company will tend to build partial processing facilities and final processing facilities on the same site.

Impacts on the Local Economy

Constructing an onshore partial processing facility may take from six months to two years depending on the size of the facility and the complexity of its equipment. Employment will fluctuate during facility construction. The development proposal for one oil and gas processing station in California estimates an average labor force requirement of 85 skilled and semi-skilled workers over a seven-month period to construct its oil processing facilities and an average force of 65 workers over an eight-month period to construct its gas processing facilities (NERBC Factbook, p. 4.49). Part-time workers may be brought in for repairs and other services.

Impacts on Natural Resources

Site Preparation -- The impacts of facility construction will vary with the size and other characteristics of the chosen site. Minimal long-term disruption to the natural environment will occur if the partial processing facility is constructed on firm land and measures are taken to minimize sediment runoff during construction. The construction of a partial processing facility requires no heavy machinery or processes which generate high levels of noise or air pollutants.

Air Emissions -- Sources of air pollution at a partial processing facility include (1) evaporation from storage tanks, (2) fuel combustion by process machinery and vehicles, and (3) leakage from valves and seals. The total volume of air emissions is a function of the design of the facility, maintenance of the processing system, and the number and design of storage tanks.

Evaporative emissions will emanate from "surge" tanks, which store the oil-water emulsion prior to processing, and from storage tanks which contain oil and gas that have been processed. The volume of evaporative losses of hydrocarbons from surge and storage tanks depends on (1) tank design (roof type, diameter, capacity, paint color, and structural condition) and (2) tank location and usage patterns (diurnal changes in vapor space, emptying and filling schedule, height of vapor space, and the pressure of stored liquids). Fixed roof tanks have "breathing losses" caused by temperature and pressure changes in the tank. Floating roof tanks may have "standing storage losses" caused by improperly fitting seals. All tanks are susceptible to "working losses" while being filled or emptied. The color of the tank surface has a significant effect on emission levels due to the heat absorption properties of different colors; white paint reflects the most light and heat and results in the least emissions. Vapor recovery systems can be used with fixed roof tanks to collect evaporative emissions and either incinerate them or send them to a small gas recovery plant; these systems can recover up to 95 percent of the emissions. Using high operating pressures in processing oil-water emulsions reduces the well stream's free vapor content and, hence, the emission of hydrocarbon gases.

Fuel combustion emissions arise from the separation process, pumps, and vehicles. Separating emulsified oil and water requires the application of heat and electrostatic action which in turn require fuel combustion. Partial processing facilities often use natural gas as the fuel source for separation processes; natural gas is a relatively clean-burning fuel. The facility may use pumps to maintain high pressures throughout the separation process. Such pumps are usually powered by gasoline or diesel fuel, which generate hydrocarbon gases, carbon monoxide, and nitrogen oxides. Trucks and employee automobiles operating at the facility will generate similar pollutants; however, vehicle traffic will probably be low and not constitute a major source of air pollution.

Chronic low-level hydrocarbon emissions may arise from leaking valves and seals, which may be the largest source of hydrocarbon emissions. These emissions may be controlled by good maintenance practices and the use of dual seals and vapor recovery systems in the design of processing equipment. The incineration of vented hydrocarbon vapors may generate sulfur oxides and nitrogen oxides; emission levels will vary with the chemical composition of the well stream. Table 5 displays estimated emissions and their source at a proposed 80,000-barrel-per-day partial processing facility in California.

Table 5
Air Emissions from a Partial Processing Facility
With an 80,000 Barrel-Per-Day Capacity (TONS/YEAR)

Emission Source	Hydrocarbons	Hydrogen Sulfide	Sulfur Oxides	Nitrogen Oxides
Crude oil heaters (8 units)	0	0	0.88	27.7
Vent vapor incinerator	0	0	4.0	0.7
Process leaks	6.6	0.2	0	0

SOURCE: NERBC, Factbook, p. 4.33 (data from USGS, Final Environmental Statement - Oil and Gas Development in the Santa Barbara Outer Continental Shelf Off California, 1976, Vol. II, p. III-194.)

Water Requirements -- Partial processing facilities require small volumes of water to heat the well stream, cool compressors, fight fires, and supply drinking and sanitary uses by facility employees. Heating system water is recirculated and periodically changed. Cooling systems require only about 100 gallons per day (NERBC, Factbook, p. 4.23). Water for fighting fires may come from on-site storage tanks or municipal water supply systems. Drinking water and sanitation will require minimal volumes because partial processing facilities have such small workforces.

Wastewater -- Partial processing facilities generate four types of wastewater: formation water (brine), cooling water, sewage, and site runoff. The formation water that exists in the well stream and is separated from oil and gas at the partial processing facility often contains high concentrations of suspended solids, dissolved solids, salts, heavy metals, and oil.

Formation water volumes, pollutant types, and pollutant concentrations vary from one well stream to another. Table 6 shows allowable pollutant concentrations from two fields off the coasts of Louisiana and California. Other chemicals are sometimes added to the well stream to break apart oil-water emulsions. Formation water must be treated before being discharged. A partial processing facility will include one or a combination of the following treatment methods: gas flotation, coalescence, filtration, and gravity separation. Each of these processes is similar to those used for well stream separation. Electrical charges or chemicals may be added to precipitate and coagulate solids and dissolved substances. Formation water must be treated and discharged carefully because of its high salinity and concentrations of hazardous substances which can be lethal to coastal aquatic environments. The discharges are regulated by state and federal agencies. Current disposal methods favor reinjection of the water into an offshore well and surface discharge far offshore.

Table 6
Allowable Pollutant Concentrations
Contained in Processed Formation Water

Pollutant	Milligrams/Liter of Water (range)	
	Louisiana	California
Oil and grease	7 - 1300	56 - 359
Total suspended solids	22 - 390	31 - 135
Total dissolved solids	32,000 - 202,000	21,700 - 40,400
Total organic carbon	30 - 1580	not available
BOD	not available	370 - 1920
COD	not available	400 - 3000
Chlorides	10,000 - 115,000	17,230 - 21,000

SOURCE: NERBC, Factbook, pp. 4.35-4.36 (data from EPA, Development Document for Interim Final Effluent Limitations Guidelines and New Source Standards for the Offshore Segment of Oil and Gas Extraction Point Source Category, September 1975, pp. 43-45).

Pumps and other process machinery may require cooling water; the volume of heated water discharged into nearby waterways will vary with cooling system design and the amount of machinery using cooling water. Discharged cooling water may also contain dissolved solids and anti-corrosion and anti-fouling chemicals. Thermal discharges, and some chemicals contained therein, can alter water chemistry by reducing the solubility of oxygen and introducing harmful substances into marine environments.

The amount of sewage generated by a partial processing facility will be insubstantial because of the small workforce. Sewage can be directed to municipal treatment facilities or treated at the site.

Accidental releases of oil, brine, and other substances may contaminate stormwater runoff from the site and adjacent receiving waters. Dikes may be constructed around storage and processing facilities to contain runoff and spills and to prevent the spread of fires.

Solid Waste -- The facility's crew must periodically remove sediment sludges from the bottom of storage and processing tanks and replace or clean processing filters. These sludges and filters are stored for special treatment and disposal; they contain numerous hazardous and non-hazardous substances that pose a threat to water quality and public health, such as oil, organic and non-organic acids, sulfur compounds, nitrogen compounds, and heavy metals.

Noise -- Partial processing facilities operate 24 hours a day. Pumps, vapor incinerators, and separation vessels all generate noise at levels of 80 to 100 decibels, above average levels for a developed area (NERBC, Factbook, p. 4.46). These levels can be reduced by enclosing pumps and separation vessels, by choosing quieter incinerator designs, and by maintaining a buffer zone around the partial processing facility. The impacts of this noise will vary with the nature of adjacent land uses (urban v. rural, residential v. industrial).

Aesthetics -- Flare stacks, 24-hour lighting, and odors may disrupt the aesthetic qualities of the landscape depending on the nature of existing land and water uses. Appropriate landscaping and buffer zones can reduce these impacts.

Fire Hazards -- The danger of fire is substantial anywhere that petroleum and gas products are processed and stored. Diking, spacing storage and processing facilities, and rapid-response firefighting equipment can keep fires small and easy to contain. Strong fire prevention measures exist at a partial processing facility to protect workers, surrounding properties, and the company's sizeable investment in equipment, oil, and gas.

Gas Processing and Treatment Plants

After partial processing separates the gas stream from the oil and water stream, a gas processing and treatment plan removes impurities from the gas stream and separates the stream's various component gasses (methane and heavier, liquid hydrocarbons). Methane, the key component of "natural gas," is then piped to commercial gas transmission lines. Liquid hydrocarbons are delivered to other processing and distribution facilities.

A gas processing and treatment plant is individually designed for the particular gas stream that it processes. Plant development decisions occur in conjunction with transportation and other processing decisions after exploration has determined the size and composition of an offshore field. There are no standard sizes or procedural configurations for gas plants; they typically range in capacity from two million to two billion cubic feet per day. A plant will contain various refrigeration units, compressors, storage tanks, and control buildings. The life span of a gas processing and treatment plant is usually ten to 20 years, depending on market conditions and offshore supplies of gas.

No specific quantity of gas justifies offshore production and the construction of onshore gas processing plants. Development decisions depend on the volume of an offshore gas field, the composition of the gas, the market for methane and liquified hydrocarbons, and production costs.

The recoverable volume of gas from an offshore field must be sufficient to outweigh the costs of recovering, transporting, and processing the gas stream. The likelihood that gas will be brought ashore for processing and marketing increases with the amount of gas in an offshore field. If an offshore reservoir contains a small amount of gas and no oil, the well may be capped and abandoned until gas prices increase enough to outweigh the costs of producing a small-volume field. If an offshore reservoir contains a small amount of gas and a "commercial" amount of oil, the gas may be reinjected into the well to maintain reservoir pressure and aid the recovery of oil.

The richer a gas stream is in liquid hydrocarbons (such as ethane, propane, and butane), the smaller an offshore field must be to justify the construction of a gas processing plant to recover these valuable liquids for sale. When gas is discovered in association with oil, the gas stream usually contains substantial quantities of liquid hydrocarbons; these will justify construction of a processing plant as long as the volume outweighs development costs. The gas processing and treatment plant separates these liquid hydrocarbons from each other and from methane (the lightest hydrocarbon gas and main constituent of commercial "natural gas"). After processing, the methane enters commercial gas transmission lines. Ethane is usually sold as input to petrochemical plants. Propane is usually sold to bottled gas distributors. Butane and heavier hydrocarbons are usually delivered as input to a refinery. Special processing equipment to recover individual components of the gas stream will not be constructed unless a market for the components exists. "Sour" gas will be treated (or "sweetened") to remove high concentrations of hydrogen sulfide before liquid hydrocarbons are separated from the gas stream. This hydrogen sulfide may justify the construction of a sulfur recovery facility at or near the gas processing plant; sulfur recovery converts hydrogen sulfide to elemental sulfur, which has industrial value.

An offshore producer usually sells natural gas (methane) at the platform to a gas transmission company, who is then responsible for installing the gas pipeline to shore. The offshore production company usually retains the rights to the liquid hydrocarbons in the gas stream and constructs and owns the gas processing and treatment plant.

The gas stream passes through four steps on its way from the offshore field to commercial natural gas transmission lines: separation, dehydration, "sweetening," and fractionation. Gas which is discovered in association with oil must be separated from the oil and formation water. Separation and dehydration occur at a partial processing facility, usually located on an offshore platform. Dehydration is essential; water vapor in the pressurized gas stream can cause corrosion or the formation of solid hydrates in underwater pipelines which interfere with the flow of gas.

If the gas stream contains high hydrogen sulfide concentrations, gas treatment, or "sweetening," facilities will usually be constructed onshore at the gas processing plant. Most industry contracts for natural gas call for the reduction of hydrogen sulfide concentrations to about 16 parts per million by volume. The "sweetening" process creates an acid by-product gas containing hydrogen sulfide, carbon dioxide, and other impurities. This acid gas may be flared off if small volumes occur. Larger volumes of acid gas may justify the construction of a sulfur recovery plant near the gas processing plant.

Fractionation is the recovery of liquid hydrocarbons from the gas stream. There are three major types of fractionation: lean oil absorption, mechanical refrigeration, and cryogenic refrigeration. The particular fractionation process used at a gas plant depends on the volume of gas being processed, the desired liquid hydrocarbon recovery rate, and the amount of liquid hydrocarbons (or "richness") present in the gas stream. Plants may use a combination of these processes. Lean oil absorption, the oldest and most common process, involves bubbling the gas stream through a gas-oil medium (similar to kerosene) which absorbs natural gas liquids. Heating the medium in another vessel separates out the liquid hydrocarbons (mostly ethane, propane, and butane). Mechanical refrigeration cools the gas stream to about -40°F, causing the heavier hydrocarbons to condense so they can be drained out of the gas stream.

Cryogenic refrigeration cools the gas stream to about -150°F using high pressures; this substantially increases the condensation and recovery rates for the lighter hydrocarbon liquids (ethane and propane). Liquifying methane, the lightest hydrocarbon, requires even lower temperatures and is rarely done for overland delivery; methane is kept in its gaseous state and delivered to commercial gas transmission lines.

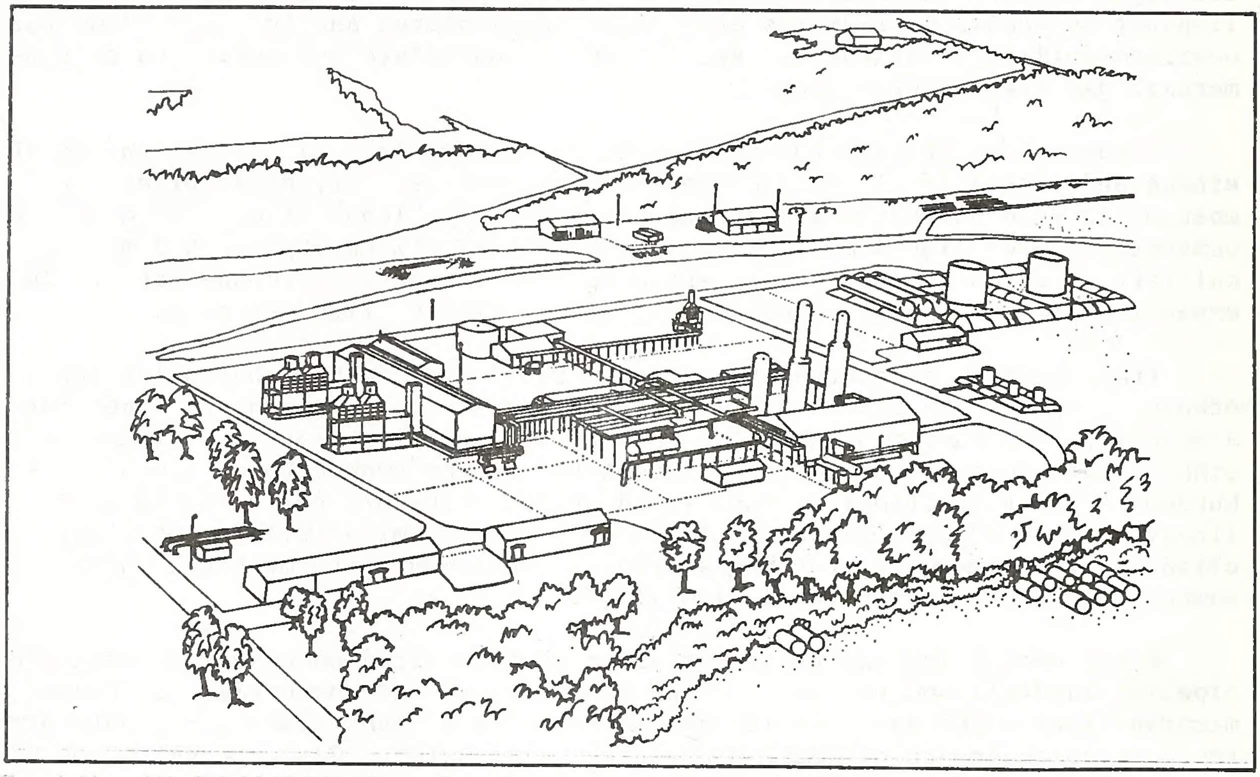
Cryogenic plants are the most expensive but yield a higher percentage of ethane and virtually all of the heavier hydrocarbons. Cryogenic plants are most often used where the gas stream is relatively "lean" (i.e., has a smaller concentration of liquifiable hydrocarbons). Lean oil absorption and mechanical refrigeration recover lower percentages of ethane and propane but are less expensive and can operate economically on relatively "rich" streams.

Fractionation separates the various liquid hydrocarbons by collecting ethane, propane, and butane at different temperatures. Each hydrocarbon has a specific temperature at which it condenses; lighter hydrocarbons (such as ethane) have lower condensation points than heavier hydrocarbons (such as butane). After fractioning, the liquid hydrocarbons are delivered to a refinery or sold to bottled gas distributors, petrochemical plants, or other clients. The remainder of the gas stream, now almost pure methane, enters commercial natural gas transmission lines.

A gas processing and treatment plant must be sited somewhere between the pipeline landfall and the junction of the pipeline and commercial gas transmission lines. The availability and suitability of land along this route are the main determinants of where a plant is constructed. Gas processing and treatment plants tend to locate in rural areas and near the coast, though a waterfront location is not necessary. Gas plants with a capacity of up to one billion cubic feet per day will require 50 to 75 acres of flat, well-drained land, of which ten to 20 acres will be used intensively for buildings and processing equipment (Figure 30). For safety, the plants have wide buffer zones between and surrounding plant operations. The industry often prefers a coastal location for a gas plant because the plant's control complex may also use VHF telemetry to control offshore platform equipment and the flow of gas through the pipeline; this process requires an unobstructed line of communication for maximum efficiency and reliability. When a coastal site is not available, this electronic control equipment may simply be mounted on towers or nearby tall buildings. A nearshore location can also reduce pipeline installation costs because the pipeline entering a gas plant is larger than that leaving the plant; locating the plant as close as possible to the pipeline landfall requires constructing a shorter, less expensive line of larger diameter pipe.

The gas processing and treatment plant must be accessible not only to pipelines but also by truck, rail, or barge. The extent to which this influences plant siting depends on what modes of transportation are available, the plant's end products, and the location of product markets. Small plants may ship products by truck; rail cars and barges tend to be more economical for transporting larger volumes. Tank trucks range in capacity from 6,000 to 10,000 gallons. Rail tank cars range in capacity from 7,000 to 34,000 gallons.

Figure 30
Gas Processing and Treatment Plant



A gas processing and treatment plant may stimulate the nearby development of such secondary industries as sulfur recovery plants and petrochemical plants. Sulfur recovery plants convert the hydrogen sulfide removed during "sweetening" into elemental sulfur. The volume of sulfur available from the gas stream, the costs of transporting sulfur to market, and the market price of sulfur will determine whether or not a sulfur recovery plant is constructed. Petrochemical plants may be developed in regions with large reserves of natural gas. The plants use ethane and other hydrocarbons as inputs for manufacturing chemicals. Large petrochemical plants are more economically feasible than small ones. The offshore gas field in a frontier region would have to be extremely large and capable of producing gas for ten to 15 years to justify the construction of a petrochemical plant. For example, a billion-pound-per-year ethylene plant requires about 27,000 barrels per day of liquid hydrocarbons with a high percentage of ethane. The discovery of oil and gas in a frontier region does not necessarily mean that the petrochemical industry will find the region to be an attractive location; several other factors, such as the market for petrochemicals and the composition of the region's gas stream, strongly influence petrochemical plant development.

Impacts on the Local Economy

The construction of a gas processing and treatment plant may take up to one and a half years and employ from 300 to 550 workers, depending on the plant's capacity (Clark et al., Recovery Technology, p. 208). Once in production, gas processing and treatment plants are highly automated and employ from approximately 21 workers for a 300 million-cubic-feet-per-day plant to approximately 55 workers for a one billion-cubic-feet-per-day plant (NERBC, Factbook, p. 5.16). Roughly 60 percent of the workers will be hired from the local labor force; the company will bring in supervisors and experienced technicians from other regions.

Impacts on Natural Resources

Site Preparation -- The impacts of constructing the gas plant and related access roads will vary with the size and other characteristics of the chosen site. Minimal long-term disruption to the natural environment will occur if the gas processing and treatment plant is constructed on firm land and measures are taken to minimize sediment runoff during construction. The construction of a gas plant requires no heavy machinery or processes which generate high levels of noise and air pollutants. Since gas processing plants tend to locate in coastal areas and underdeveloped rural areas, the industry and local governments should take care to protect sensitive coastal environments, such as wetlands, from unwise industrial siting and development decisions. The risk of such environmental disturbances and the costs of construction will be minimized if the plant is constructed on firm land.

Air Emissions -- The volume of gas processed at a gas plant, the composition of the gas stream, plant design, and the choice of pollution control equipment will determine the magnitude of air emissions and all other environmental impacts arising from the plant's operation. Air emission sources at a gas processing and treatment plant include processing, incineration, evaporation, and fuel combustion by vehicles and processing equipment.

Tail gases from "sweetening" and sulfur recovery contain various amounts of hydrogen sulfide. These tail gases are burned off, with fuel added to ensure complete conversion. This burning converts hydrogen sulfide to sulfur dioxide, which is then vented through a stack to the atmosphere. The level of sulfur dioxide emissions will depend on the volume and hydrogen sulfide concentration of the gas stream. Incineration of tail gases also generates small quantities of nitrogen oxides, particulate matter, and hydrocarbons. Evaporative emissions of hydrogen sulfide and hydrocarbons may also occur during gas processing and treatment and can be controlled by vapor recovery devices placed at control valves, pipe joints, and vessel drainage points. Evaporative emissions increase with the volume of the gas stream.

Compressors and boilers at the gas processing plant use natural gas as a fuel and emit nitrogen oxides, hydrocarbons, and sulfur oxides. The level of these emissions will vary with the volume and composition of fuel used; emissions may be lowered by using cleaner gas and more efficient firing methods. Emissions from employee automobiles and trucks which carry plant products will contain carbon monoxide, hydrocarbons, and nitrogen oxides.

Water Requirements -- The total water requirement of a gas plant varies with the volume of gas processed and the cooling system design used at the plant. Air-cooled processors use much less water than water-cooled systems. A typical plant uses about 1,500 gallons of water per million cubic feet of gas processed. Most plants use less than 200,000 gallons per day (NERBC, Factbook, p. 5.14). Water will come from wells, nearby surface sources, or municipal water systems.

Wastewater -- A gas processing and treatment plant generates four types of wastewater: cooling water, process water, sewage, and stormwater runoff.

Cooling water may constitute 70 to 100 percent of the wastewater volume from a gas processing plant when the plant uses water-cooled equipment. "Once-through" cooling systems do not recycle cooling water and, hence, produce the greatest thermal discharges. "Closed cooling tower" systems can recycle cooling water up to five times before discharging it. These systems require very clean intake water in order to operate most efficiently. The partial evaporation that occurs with each passage of recycled water increases the concentration of dissolved and suspended solids it contains. In addition to the thermal discharge, these substances, and chemicals added to prevent corrosion and fouling in the cooling system, may prove toxic to aquatic organisms. Reducing pits and other treatment methods can precipitate most of these chemicals out of the cooling water stream; the chemicals may then be disposed of at a landfill. Cooling ponds and other methods can bring the cooling water down to a temperature more in line with that of receiving waterways.

Process water includes any water which comes in contact with the well stream. Formation water (brine) is usually removed and discharged by a partial processing facility. The process water discharged by a gas processing plant may include additional formation water removed at the dehydration stage, spent caustic solutions, and wash waters. These discharges can be treated to remove oil and other hazardous substances before they enter adjacent waterways.

A gas processing and treatment plant will generate small amounts of sewage because of its small workforce. If properly handled by on-site treatment or delivery to a municipal treatment plant, this domestic wastewater should cause no significant environmental impact.

Gas plants store large quantities of oil, liquid hydrocarbons, and other hazardous substances. Accidental leaks of these substances can contaminate site runoff. Contaminated runoff can adversely affect organisms in adjacent waterways unless it is collected and treated before discharge or the receiving waterway is already heavily polluted.

Solid Wastes -- A gas processing and treatment plant will generate general rubbish and specialized solid wastes. General rubbish includes packaging materials, waste paper, scrap metal, and the like, and presents no significant environmental problems. Specialized solid wastes which result from the plant's operation include several hazardous substances, such as sediment sludges, spent filter materials, contaminated sulfur, and iron oxide/wood chip "sponges" used in "sweetening" the gas stream. These substances must be specially stored and disposed to prevent the contamination of surface water, ground waters, and the air. Some of these solid wastes can be treated or specially incinerated to reduce their volume and toxicity.

Noise -- A gas plant's compressors, flare stacks, and treatment equipment will generate noise above ambient levels on a 24-hour basis. These levels can be reduced by enclosing compressors and treatment vessels, using quieter flare stack designs, and installing mufflers on compressors and other equipment. The impacts of this noise will vary with the nature of adjacent land uses. For example, a flare stack generating 80 decibels will exceed ambient noise levels over one-half mile away in a rural area with an average noise level of 40 decibels (NERBC, Factbook, p. 5.32). Gas processing plants usually have wide buffer zones for safety reasons; these also help attenuate noise from the plant.

Aesthetics -- Flare stacks, 24-hour lighting, large processing vessels, and gas odors may disrupt the aesthetic qualities of the landscape depending on the nature of existing land and water uses. Gas processing plants always have ample buffer zones which may help reduce the plant's visual impacts, especially when they are combined with appropriate landscaping. The incomplete combustion of hydrogen sulfide gas can create unpleasant odors; more efficient combustion methods can eliminate this problem.

Safety Hazards -- Even though gas plants have a low risk of explosion and fire, the potential magnitude of damage is very high. All the products of a gas plant are inflammable; escaping vapors and liquids can create critical concentrations in the air which increase the chance of fires and explosions. Such catastrophes are unlikely if equipment at the plant is routinely inspected and maintained and plant design and construction follows appropriate codes and industry standards. Processing equipment and storage tanks are typically surrounded by substantial buffer zones and dikes to limit the spread of spills and fires. The entire plant is well equipped with firefighting equipment to protect workers and the company's substantial investment in equipment, natural gas, and gas products.

Marine Oil Terminals

Waterborne shipments of crude oil require the construction of marine terminals, which contain loading and unloading facilities, storage tanks, and vessel berths. There are three types of marine terminals:

1. receiving terminals - which unload tankers carrying crude oil from offshore production platforms or from other regions for delivery via pipeline to a nearby refinery

2. transshipment terminals - which load crude oil received by pipeline from offshore production platforms onto tankers for delivery to refineries in other regions, and

3. product terminals - which unload refined petroleum products from tankers and store them for truck or rail delivery to local markets.

The following description focuses on receiving terminals and transshipment terminals since these are more closely associated with offshore oil production in a given region. The construction of product terminals depends more on the national and local demand for petroleum products and the individual oil company's marketing strategy than on the existence of offshore oil.

Receiving terminals perform an important flow modification function. Tankers move oil in bulk quantities which create temporary surges in supply. Refineries handle oil at a constant rate of flow. Receiving terminals can store the oil unloaded from tankers and deliver it to the refinery at a consistent flow rate. If offshore oil is loaded onto tankers or barges at the platform rather than piped ashore, the oil will probably be delivered directly to an existing refinery (inside or outside the region), which will be served by a receiving terminal. Transshipment terminals arise when crude oil from offshore platforms is destined for refineries located outside the region or when it is prohibitively expensive to construct an overland pipeline from a marine pipeline landfall to a refinery.

Marine terminal siting decisions are made at the same time as and in conjunction with other OCS transportation and production decisions. Terminal locations and pipeline routes are selected to minimize the costs of constructing and operating the total transportation system which carries oil from the offshore field to the refinery. The general location of a transshipment or receiving terminal handling a region's offshore oil is determined by the shortest route between the oil field and the shore and the oil field and the refinery. Transportation economics and land suitability will determine the specific location of the terminal. The terminal may be established in an existing developed harbor if the harbor is close to the offshore oil field or pipeline landfall, has a sufficient channel, and has land suitable for a tank farm. Though it is not necessary to locate a tank farm adjacent to loading and unloading berths, companies usually do so to eliminate duplicating offices and safety equipment, to use less land, to lower the costs of overland pipeline construction (from the berth to the tanks), and to more easily oversee and control loading and storage operations. Tank farms may be located away from the terminal if suitable land is not available along the waterfront; pipelines will carry oil from the berth to the storage tanks.

A marine oil terminal consists of vessel berths, large steel storage tanks, oil pumping equipment, fire fighting equipment, pipelines, and administration and control offices. The size of a terminal's berthing and storage facilities is a function of the volume of flow between the terminal and the refinery, the size of the tankers and pipelines supplying the terminal, the frequency of tanker arrivals, and the expected duration of adverse weather conditions. A terminal should have enough storage capacity to avoid the curtailment of field production and should have adequate berth capacity to provide the fastest possible turn-around time for tankers. A large storage capacity is needed in regions with frequent adverse weather conditions which interrupt tanker operations.

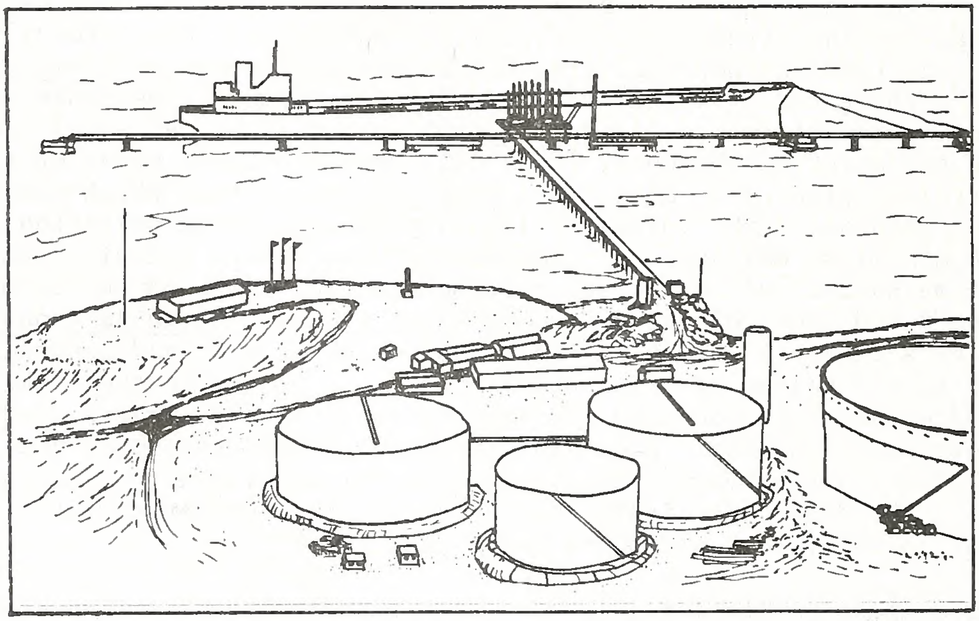
Storage tanks occupy most of the land at a marine terminal and tank farm. Acreage requirements vary with the terminal's storage capacity and whether it contains such other onshore facilities as partial processing plants. A one-million-barrel capacity tank farm occupies about 17 acres; a three-million-barrel tank farm occupies about 50 acres (NERBC, Factbook, p. 3.67). The land should be flat, not subject to flooding, and have sufficient load-bearing strength (at least 7,000 pounds per square foot) to support storage tanks without settling (Clark et al., Recovery Technology, p. 173). The three basic designs for petroleum product storage tanks vary primarily by roof type. A fixed roof tank is a cylindrical steel tank equipped with pressure/vacuum vents; it is the least expensive means of storing most petroleum products. A floating roof tank has a roof which rises and falls in response to the volume of liquid products and vapor in the tank; the tank minimizes emissions of hydrocarbon vapors into the air. The tank contains mechanical seals between the roof and walls and may be covered by a second, fixed roof to further reduce vapor losses. Variable vapor space tanks have a flexible, diaphragm-like roof which expands and contracts in response to the volume of vapor above the liquid stored in the tank; variable vapor space tanks are not used for storage of crude oil but are used to store other petroleum products. Each storage tank is surrounded by a concrete or earthen dike which excludes floodwaters and retains oil if a tank leaks or ruptures. The dikes facilitate the collection of stormwater runoff for treatment to remove oil and other contaminants.

For maximum navigational safety, a marine terminal location should (1) have a channel that is deep enough to accommodate the largest expected tanker, (2) have a turning area with a width two to four times the tanker's length, (3) be in a relatively uncongested harbor with good navigational aids, and (4) sheltered from adverse winds, waves, and currents. Offshore mooring and loading stations may be constructed if natural deepwater harbors are not available.

Three types of berthing facilities exist at marine terminals: shoreside fixed piers, offshore fixed piers, and offshore floating moorings. A shoreside fixed pier (Figure 31) is usually located inside a harbor; the pier will lay parallel or perpendicular to the shoreline depending on channel currents, channel width, prevailing wind direction, the availability of waterfront land, and the availability of tugs. The pier's main components are the loading platform, breasting dolphins, mooring dolphins, and trestle. The loading platform supports the loading arms, operation control building, firefighting equipment, lighting towers, and all other operating equipment. Breasting dolphins are fenders mounted on rigid or flexible platforms which withstand berthing impacts from the tanker and mooring stresses from wind, waves, and currents. Mooring dolphins are concrete and steel pile platforms to which the tanker attaches its mooring lines. The trestle connects the shore to the loading platform and supports all piping which carries oil between the tanker and the terminal's storage tanks. Additional steel truss walkways connect the loading platform to the breasting dolphins and connect the mooring dolphins to shore.

An offshore fixed pier, or "sea island pier," consists of a similar loading platform, breasting dolphins, mooring dolphins, and interconnecting

Figure 31
Shoreside Fixed-Pier Terminal



walkways. A sea island pier is not connected to the shore by a walkway; submarine pipelines carry the oil to shore. Tankers can dock at both sides of the pier, which is oriented to the most favorable wind, wave, and current direction. Sea island piers usually consist of a reinforced concrete deck supported on steel or concrete piles which are firmly attached or driven into the sea bottom.

An offshore floating mooring consists of an anchored mooring buoy, floating hoses connecting the tanker to the buoy, and submarine hoses connecting the buoy to submarine pipelines which run to the storage terminal. Petroleum products are pumped between the tanker and the terminal via the submarine pipeline, the buoy, and the floating hoses. The mooring buoy is designed to resist variable mooring stresses and allows the tanker to shift position in response to wind, wave, and current directions while transferring cargo. Offshore floating moorings may also be used at offshore platforms to load tankers.

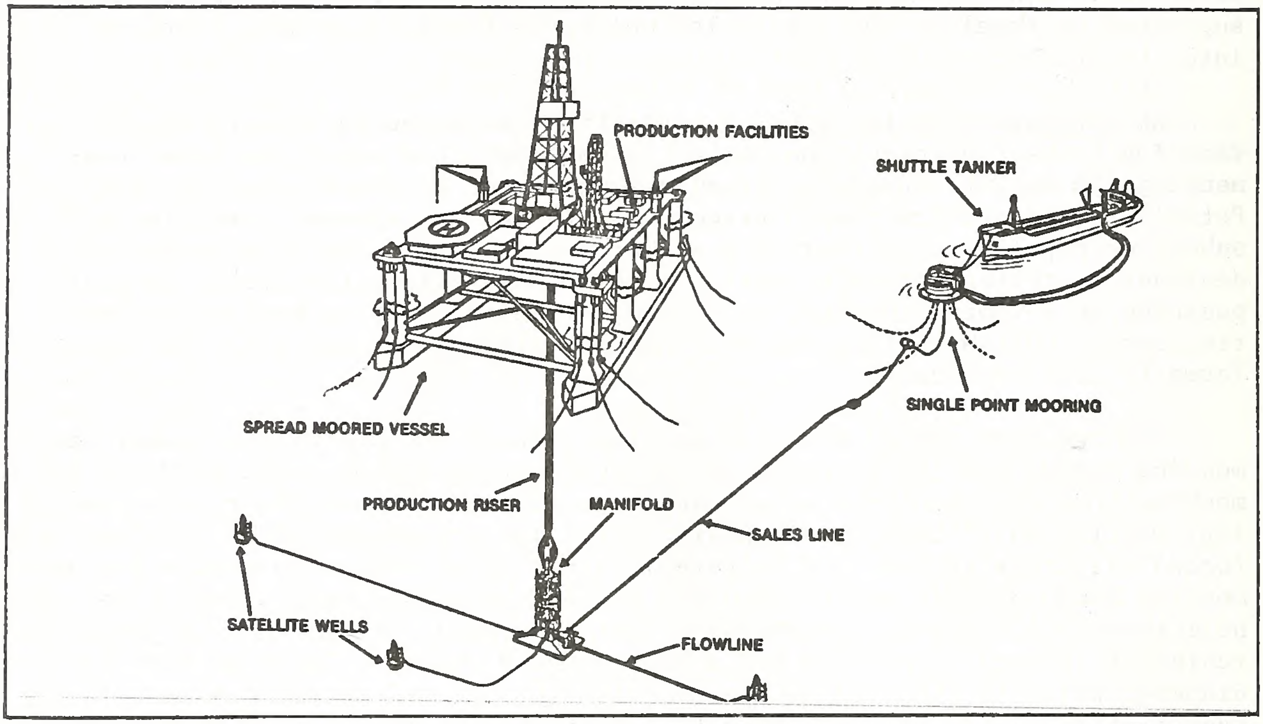
The two most common floating mooring systems are the single anchor leg mooring (SALM) and the catenary anchor leg mooring (CALM). The SALM has a mooring buoy anchored by a single leg to a base on the sea floor. The anchor leg, mooring buoy, base, and submarine pipeline are connected by a reinforced oil transfer hose and universal joints which allow the anchor leg and mooring buoy to shift positions. The mooring buoy is a cylindrical steel hull roughly 13 feet in diameter, 56 feet high, and surrounded by impact-resistant fenders. The CALM has a mooring buoy which is 30 to 50 feet in diameter which is attached to the sea floor by several anchor chains. The tanker attaches its mooring lines to a turntable on the buoy which allows the ship to shift position (or "weathervane") while transferring oil (Figure 32). The turntable also supports a rotating pipe assembly which is connected to submarine hoses and the tanker's loading hoses.

Crude oil tankers vary in size from 10,000 deadweight tons (DWT) for coastal tankers to 150,000 DWT for supertankers to 400,000 DWT for "very large crude carriers" (VLCCs). Tankers using inland harbors average 40,000 DWT and range up to 70,000 DWT (NERBC, Factbook, p. 3.60). Table 7 shows the dimensions, pumping rates, and draft requirements of tankers ranging from 20,000 DWT to 250,000 DWT.

Oil storage terminals may contain several water collection and treatment systems. A small treatment system handles domestic sewage or transports it to a municipal treatment system. One stormwater collection system discharges unpolluted runoff. Another stormwater collection system collects runoff and process water that is contaminated by oil and other substances; the system contains oil separation equipment and aeration ponds to clean the water prior to discharging it. Additional treatment facilities will be needed if tankers discharge ballast water at the terminal.

Oil storage terminals are also equipped with firefighting facilities (pumps, trucks, and hoses) which draw water from the adjacent waterway, a pond constructed on the site, or the municipal water system. Oil storage terminals usually contain a small electric power substation to "step down" high voltage power for use by the terminal's pumps and other equipment.

Figure 32
Relationship of Single Point Mooring
System to Production Platform



SOURCE: National Academy of Science, Outer Continental Shelf Frontier Technology, p. 108.

Table 7
Tanker Dimensions and Pumping Rates

Tanker Sizes (x 1000)		Length	Beam	Loaded Draft	Max. Tons Water Per Hour	Pumping Rates Barrels Oil per Hour
DWT	Barrels					
20	140	580	72	32	2,000	14,000
40	280	715	93	37	4,000	28,000
50	350	740	105	39	4,000	28,000
70	490	800	117	41	6,000	42,000
100	700	850	128	49	8,000	56,000
150	1,050	980	149	54	10,000	70,000
250	1,750	1,125	170	65	13,000	91,000

SOURCE: NERBC, Factbook, p. 3.61 (data from Arthur D. Little, Inc. and Frederic R. Harris, Inc., Petroleum Development in New England, 1975, Vol. II, p. IV-19).

Impacts on the Local Economy

Labor requirements for marine terminals vary according to the size and type of facility. The highest level of employment will occur during the construction phase; terminal operations require a much smaller workforce due to the high level of automation in oil transfer and storage. Construction employment may range upwards of 550 workers. The proportion of construction workers hired from the local labor force will depend on the availability of workers with the necessary specialized skills. Employment during terminal operation may range from 25 to about 90 workers depending on the terminal's capacity (NERBC, Factbook, pp. 3.72-3.74). This includes maintenance and other specialized personnel hired on a part-time contractual basis. Roughly 70 percent of the operational workers may be hired from the local labor pool. Table 8 shows estimates of the labor requirements of different types of terminals during construction and operation.

Table 8
Employment at Selected Marine Terminals and Storage Tank Farms

	Fixed Shoreside Terminal	Fixed Offshore Terminal	Floating Mid-depth Terminal
Throughput rate (barrels/day)	250,000	250,000	250,000
Maximum Tanker Size (deadweight tons)	50,000	150,000	150,000
Draft (feet)	40	50-60	50-60
Total Storage Capacity (barrels)	1,000,000	2,000,000	2,000,000
Storage Tanks (number of tanks x barrel capacity)	4 x 250,000	2 x 250,000 3 x 500,000	2 x 250,000 3 x 500,000
Direct Construction Employment	565	810	667
Direct Operation Employment	89	89	64

SOURCE: NERBC, Factbook, p. 3.72 (data from Arthur D. Little, Inc. and Frederic R. Harris, Inc., Petroleum Development in New England, Vols. II and III, 1975).

Site Preparation -- As with other onshore OCS-related facilities, the impacts of constructing a marine terminal will depend on the existing characteristics of the particular site. Shoreside fixed piers may involve altering the shoreline and dredging a new channel or turning basins, which may alter water circulation and erosion patterns and temporarily increase turbidity in the harbor. Offshore fixed piers and offshore mooring buoys usually do not involve dredging a new channel. The major impact of their installation will arise from pile-driving and the laying of submarine pipelines.

Onshore pumping and storage facilities may be located at the waterfront or several miles inland. Constructing these facilities takes 12 to 18 months. During this time, the soil surface will be exposed and leveled. Wind and rain may easily erode the exposed soil and carry it into adjacent land and waterways. Runoff from the site may contain eroded soil, solvents, paint, spilled fuel, heavy metals, and particulates from site clearing, welding, sandblasting, and other activities involved in fabricating storage tanks and other facilities. These pollutants can alter the chemistry and biological productivity of nearby waterways. Fuel combustion by heavy construction equipment may emit nitrogen oxides, carbon monoxides, and hydrocarbons into the air. Heavy equipment, especially pile-drivers, may substantially increase noise levels at the construction site. Solid wastes generated during construction (packaging materials, scrap timber, and scrap metal) may be sold as scrap or disposed of on-site or at a nearby incinerator or landfill. Hazardous wastes must be specially treated and disposed.

Air Emissions -- Air emission sources during the operation of a marine terminal and tank farm include evaporation from storage tanks and oil transfer operations, fuel combustion by machinery and vehicles, and accidental spills and leaks. As with other environmental impacts, the magnitude of air emissions depends on the capacity of the terminal, operating procedures, and the design of storage tanks and other equipment.

The volume of evaporative losses of hydrocarbons from storage tanks at a terminal depends on (1) tank design (roof type, diameter and capacity, paint color, and structural condition) and (2) tank location and usage patterns (diurnal changes in vapor space, emptying and filling schedule, height of vapor space, and the pressure of stored liquids). (See the discussion of evaporative losses under Partial Processing Facilities.) Techniques to minimize evaporative emissions caused by the solar heating of tanks include water sprays, tank burial, mechanical cooling apparatuses, and avoiding filling and emptying tanks during the hottest time of the day. The transfer of fuel, crude oil, and other petroleum products at the terminal from tankers to storage tanks and from storage tanks to tankers) which consume fuel as well as deliver it to offshore sites) also causes evaporative emissions. The quantity of these vapor losses depends on the temperature, density, and vapor pressure of the fuel, and how saturated the vapor space is at the time of unloading. Considerable evaporative emissions may also occur while the tanker is docked or in transit. Table 9 presents typical evaporative emissions associated with fuel transfer operations.

Table 9
Typical Evaporative Emissions
from the Transfer of Crude Oil*

Operation	Emissions
Boat unloading	2.3 lb/1000 gallons transferred
Boat loading	2.6 lb/1000 gallons transferred
Boat transit	3.2 lb/week per 1000 gallon load

*assumed temperature: 63°F
assumed vapor space saturation: 20 percent

SOURCE: NERBC, Factbook, p. 3.86 (data from EPA, Compilation of Air Pollutant Emission Factors, 2nd ed., 1976, p. 4.4-8).

Fuel combustion by tankers, trucks, heavy machinery, and employee automobiles will release hydrocarbons, carbon monoxide, and nitrogen oxides into the air. The evaporation of accidental releases of crude oil and other substances will constitute a minor source of air pollution at the terminal.

Water Requirements -- Water requirements at a marine terminal will be minimal, except when the terminal contains oil processing facilities which require cooling and process water. Firefighting equipment at the terminal requires a ready, large supply of water; this may be pumped from the adjacent waterway, an on-site storage tank, or a municipal water supply system.

Wastewater -- The operation of a marine terminal may generate six types of wastewater: sewage, bilge water, ballast water, cooling water, process water, and stormwater runoff. Sewage from the marine terminal can be treated at the site or delivered to a municipal treatment system. Bilge water, which collects in the lower sections of tankers and other boats, often contains petroleum products and metallic compounds which leak from machinery. Bilge water is collected at the terminal or an adjacent port facility for treatment prior to discharge.

Ballast water is taken in by empty tankers to improve vessel handling after unloading crude oil; ballast water will fill the tanker to about 40 percent of capacity. From 0.2 to 0.4 percent of an oil shipment will remain on storage compartment walls after a tanker has unloaded and taken in ballast water (NERBC, Factbook, p. 3.91). The composition of ballast water depends on the products carried by the tanker. Ballast water often has a high biological oxygen demand (BOD) and high concentrations of fecal coliform bacteria and heavy metals, which can be toxic to aquatic organisms and contaminate recreational waters.

Marine terminals usually have equipment to treat ballast water and reduce oil concentrations to meet federal effluent standards before discharging the contaminated water. Treatment procedures are available which recover oil from ballast water and return it to oil storage and processing facilities. New tankers may have special tanks exclusively for ballast water to avoid contamination by oil.

Pumps, other processing machinery, and on-site electrical generators may take in and discharge cooling water. The volume of thermal discharges will depend on the number and design of the equipment and cooling systems. Thermal discharges can cause lethal shock to aquatic organisms and alter the chemistry of waters receiving the discharge. Cooling water may also contain dissolved solids, heavy metals, and biocides which are added to prevent equipment corrosion and fouling. As with other wastewater discharges, thermal discharges are controlled by federal and state regulations.

The oil transfer terminal on an offshore platform will have special equipment for removing and treating some of the wastes which are present in the oil as it is pumped from the field. These impurities normally include brine, suspended solids, nitrogen compounds, sulfur compounds, oxygen compounds, and small amounts of metals. Sulfur compounds are either flared or converted to elemental sulfur. Nitrogen oxides are converted to ammonia. Oxygen compounds are converted into water. A desalter separates brine from the oil stream. Brine can constitute 10 to 50 percent of the total fluids in the stream. Brine waters often have a high temperature and high concentrations of oil and suspended solids. Treatment facilities at the platform or marine terminal can remove most of the oil from the brine and lower its temperature before discharge into coastal waters. Disposing brine into surface waters requires a federal permit under the National Pollution Discharge Elimination System (NPDES); brine is frequently disposed of by deep-well injections regulated by states (within the territorial boundaries) and the federal government (on the outer continental shelf).

Stormwater runoff at a marine terminal is contained by dikes around storage tanks and other facilities. Stormwater runoff is held in storage ponds and treated to remove oil and other contaminants before being discharged into adjacent waters.

Solid Waste -- Much of the solid waste volume generated by a marine oil terminal consists of (1) chemical sediments produced with the crude oil or precipitated during storage and (2) sludges and other residues from the treatment of oil, brine, and wastewater. Sediment sludges are periodically removed from the bottoms of storage tanks and pipelines, as part of the routine maintenance of the terminals, and stored for subsequent treatment and disposal. Rust, iron sulfides, sand, and oil are the major constituents of these sludges. Oil/brine separation and wastewater treatment for oil removal also produce large volumes of waste sludges which contain oil, sulfur compounds, nitrogen compounds, and heavy metals.

The sludges handled at a marine terminal contain numerous hazardous and toxic substances. Marine terminals often have open sludge storage pits which allow chemical wastes to enter the air, soil, surface waters, and groundwaters. No serious environmental effects will result if adequate treatment, storage, and disposal facilities exist; otherwise, environmental damage may be substantial.

Noise -- Noise at a marine terminal will come from processing equipment, such as pumps and compressors, and from oil tanker engines. Since tanker schedules determine the terminal's hours of operation, noise may occur at any time of day. Compressors generate noise at up to 100 decibels, well above ambient levels in most areas. The terminal may be surrounded by a buffer zone; its processing equipment may be equipped with mufflers or enclosed to protect workers and users of adjacent property.

Aesthetics -- A marine terminal may significantly deteriorate the visual quality of the surrounding landscape depending on the initial condition of the terminal site and the nature of adjacent land and water uses. Storage tanks are quite large; tanks and berths are lighted 24 hours a day. Visual impacts may be lessened by vegetated buffer zones and other screening techniques.

Oil Spills and Fires -- Small accidental discharges of oil may occur continually at a marine terminal; these leaks from tankers and onshore storage tanks can combine with the oil found in process water, ballast water, bilge water, and stormwater runoff to create chronic low-level oil pollution in adjacent waters. Little evidence currently exists on the impacts of continuous low-level concentrations of oil in aquatic environments. Such small spills or discharges may be minimized by new tanker designs, oil loading procedures, and on-site wastewater treatment practices.

Large spills will occur less frequently, but will receive major attention and may have significant short-term and long-term impacts on the aquatic environment. Methods for containing and treating oil spills already exist; the key to minimizing the impacts of oil spills is rapid response. A good oil spill contingency program will have cleanup equipment readily available at the terminal or at some nearby harbor facility and will swiftly put the equipment into operation at the first sign of a spill. Oil spill containment and cleanup is easier in waterways with slow currents and minimal wind and wave action.

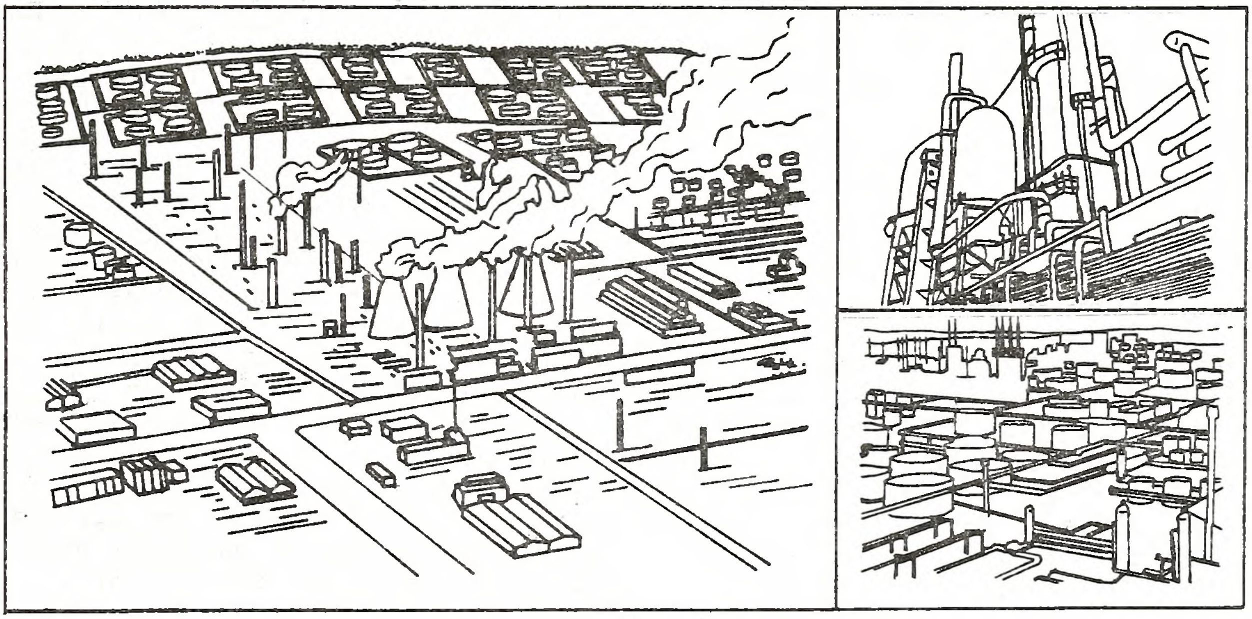
The large volumes of oil stored at a marine terminal create a substantial fire hazard. However, fires are infrequent; marine terminals have extensive precautionary procedures and fire detection and extinguishing equipment. The storage tank area has complete water and foam extinguishing systems with portable extinguishers located throughout the terminal. Storage tanks often have individual foam systems which, when triggered, can rapidly cover an entire tank with foam. Berthside firefighting systems are usually self-contained and have a foam system and a water system, which may pump water directly from the harbor. The fire protection system at a marine terminal and tank farm must meet the requirements of the National Fire Prevention Association and the U.S. Occupational Safety and Health Act as well as state and local fire prevention regulations.

Refineries

A refinery converts crude oil into a number of useful petroleum products, such as gasoline, kerosene, diesel fuel, and heating oil, by physically and chemically altering all or part of the crude oil stream. A series of processing units at the refinery separates the crude oil stream, converts it and blends it into valuable hydrocarbon compounds, and treats it to remove impurities. In addition to processing units, a refinery contains storage tanks, roads and rail lines, water treatment facilities, maintenance shops, loading terminals, and offices (Figure 33). Refineries tend to locate near large centers of demand rather than where oil supplies are greatest. Refinery development decisions involve several important economic considerations and are usually made independently of offshore oil discoveries and production; a frontier region does not require a refinery to serve offshore development.

The crude oil arrives at a refinery via pipeline or tanker and is stored to await processing. Refining is more economical with a steady flow of oil than with large fluctuations, or surges, in the processing stream; storing the crude oil when it arrives allows the refinery operations to maintain such

Figure 33
Oil Refinery



a steady flow. In the highly automated refining process, the crude oil stream may undergo four different operations: separation, conversion, treatment, and blending. The operations chosen and the complexity of the processing system depend on the characteristics of the crude oil and the desired mix of final products. In the *separation* process, distillation fractions the crude oil into light, intermediate, and heavy hydrocarbon groups and removes inorganic salts. The *conversion* process chemically alters these groups into more desirable products by alkylation, polymerization, catalytic reforming, and hydro-cracking. *Treatment* removes contaminants, such as hydrogen sulfide, from the various products. Hydrocarbon products may then be *blended* to create an even wider variety of products, such as different blends of gasoline. Highly refined products, such as gasoline, require more complex refining processes. Refinery designs try to allow an easy change in processing methods to produce a different final hydrocarbon mix to meet changes in the demand for individual products. After processing, the refinery's final products are stored and then distributed by pipeline, tanker, rail, or truck.

Refineries are usually owned by an independent refiner or by a major oil company. The designs and product mixes of major oil company refineries tend to reflect national demand patterns. The designs and product mixes of independent refineries tend to respond more to regional demands.

The principal factors influencing the decision to build a new refinery are (1) the market for refined petroleum products and (2) the long-term availability of crude oil from offshore fields and other sources. There is currently no direct correlation between the discovery of offshore oil fields and the construction of refineries in adjacent onshore communities, especially if the offshore fields are reasonably close to existing refineries that are operating below capacity. A strong possibility for new refinery construction does exist in a frontier region with substantial offshore oil reserves, a substantial onshore demand for petroleum products, and few if any existing refineries.

The oil industry prefers to build refineries close to major consumption markets. It is more economical to transport a large quantity of crude oil over a long distance than to distribute a variety of products to market via many smaller transportation facilities. Since refinery construction requires a massive capital investment, the oil industry will not build a refinery unless it is sure that the demand for petroleum products is large and will remain large for many years. If the demand for refinery products is slowly increasing, a refiner may add capacity to an existing refinery rather than build a new one; this strategy requires a smaller capital investment and has a shorter payback period. The oil industry will not build a new refinery unless it is sure that long-term supplies of crude oil are available. Refineries tend to draw crude oil supplies from several domestic and foreign production fields rather than from a single offshore region, which may produce relatively limited quantities of oil over only ten or fifteen years.

The actual site chosen for a new refinery will depend on (1) the availability of land and water, (2) the site's accessibility to transportation systems and other oil industry facilities, and (3) environmental regulations and public attitudes. A refinery processing from 250,000 to 500,000 barrels of crude oil per day is likely to require from 1,000 to 1,750 acres of flat, well-drained land that is above the flood zone and capable of supporting heavy storage tanks and processing equipment (NERBC, Factbook, p. 6.50). About half of the land will constitute a buffer zone around the processing units and storage tanks. This additional land may be used in the future to accommodate refinery expansions. While a refinery does not require a waterfront location, it must have access to large supplies of water. The actual amount of water a refinery uses will depend on the capacity of the refinery, the product mix, the processing and cooling system technology, and the initial quality of intake water.

Refineries must also have good transportation access. In coastal areas, they are usually sited adjacent to deep navigable waterways because crude oil, refined products, and construction materials are often carried to and from the refinery by tanker, barge, or cargo ship. Refineries require good access to well maintained railroads and highways since refinery products may also be delivered by train or tank truck; trucks are mainly used to supply local markets. Access to crude oil and refinery product pipelines will also influence the industry's siting decision.

Coastal refineries generally require the construction of a marine oil terminal to handle tankers and barges. If the refinery is located at the waterfront, the terminal will be part of the overall refinery complex. If the refinery is not located along the water, a crude oil pipeline, with a right-of-way 50 to 100 feet wide, will have to be constructed to link the terminal to the refinery.

A refinery must have access to a large electrical power network if it does not generate its own electricity. A 250,000 barrel-per-day refinery will use about 100,000 kilowatts of electricity (NERBC, Factboook, p. 6.14). Electricity constitutes about 80 percent of the power consumed at a refinery. The remaining power tends to come from low-sulfur fuel oil and gas produced at the site.

Refineries can meet existing state and federal environmental standards; except for air quality limitations, pollution control regulations do not appear to strongly influence refinery siting decisions. Mainly because of the time and costs of litigation, refiners tend to avoid environmentally sensitive locations. Refiners also tend to avoid communities with a history of determined opposition to major heavy industrial development. Oil refineries are the most controversial facilities in the oil and gas production system.

Impacts on the Local Economy

A refinery takes about one year to design and three years to construct. Constructing a 250,000 barrel-per-day refinery may require an average of 1900 to 2200 workers, with a peak employment of up to 3500 workers (NERBC, Factbook, p. 6.16). Smaller refineries will require slightly fewer workers; larger refineries will require slightly more. Local hiring during the construction phase may range from 30 to 70 percent depending on the size of the local labor force and the skill categories available (NERBC, Factbook, p. 6.16). Contracting companies will typically import skilled workers if few are available locally and house them in temporary quarters at the construction site. Refinery construction requires welders, pipefitters, electricians, equipment operators, general laborers, and other personnel.

Once the refinery is operating, the total number of employees falls but is still a significant demand for most communities to absorb. Employment at a refinery may vary from about 400 to over 600 workers depending on the size of the refinery. The refinery workforce may be even larger if maintenance personnel are employed in-house rather than contracted from other firms. Up to 80 percent of the operating workforce may be recruited from the local workforce if appropriate workers are available; most refinery employees are skilled or semi-skilled workers who receive on-the-job training. Ten to 20 percent of the refinery staff perform administrative duties. About ten percent perform specialized support functions (laboratory work, safety monitoring, etc.). The remaining 70 to 80 percent perform operation and maintenance tasks. The administrative and specialized support workers are those more likely to be imported from other areas.

Impacts on Natural Resources

Site Preparation -- Refinery construction involves extensive clearing and grading which exposes soil at the site to wind and water erosion. Extensive trenching and excavation will likely occur for installing pipelines and wastewater treatment ponds. A refinery constructed in a coastal community will probably involve dredging and other site alterations for constructing a marine oil terminal. The size of refineries and the tendency for refineries to locate near shorelines increase the likelihood that refinery construction will disturb or displace coastal wetlands. The impacts of construction will depend primarily on the site chosen for the refinery; the construction of refineries on firm and non-eroding shorelines will have fewer impacts than construction in or near more sensitive environments. In addition to sediment runoff, the extensive metal fabrication and painting involved in refinery construction create a risk of runoff contaminating adjacent waterways. Runoff contamination and sedimentation may be controlled by good housekeeping practices and sedimentation control devices.

Air Emissions -- The three major sources of air pollutants at a refinery are (1) refining processes, (2) fuel combustion by vehicles and processing equipment, and (3) leaks and evaporation from valves and seals at processing units and storage tanks. As with all other environmental impacts, the magnitude of air emissions will depend on the amount of oil refined, the crude oil's chemical characteristics, plant design, and government emission standards.

Processing emissions come primarily from catalytic cracking and coking operations. Catalytic cracking alters the molecular structure of hydrocarbons by heat and catalytic conversion; the process gives off carbon monoxide, sulfur oxides, hydrocarbons, and particulate matter. Spent catalysts from the cracking process are reclaimed by passing them through a vessel which burns off residual coke and primarily generates particulate matter. Coking is a decarbonization process which increases the crude oil stream's yield of lighter, distillate fuels (such as gasoline) relative to its yield of heavier residual fuel oils. Particulate emissions from cracking and coking may be substantially reduced by using electrostatic precipitators ("scrubbers"). Table 10 shows emissions from each process.

Vehicles and processing machinery at a refinery contribute significant amounts of air pollutants. Processing machinery includes compressors and external combustion boilers. Emission volumes depend on the number and size of the boilers and compressors and the fuel used to power them. Table 11 summarizes average emissions from boilers and compressors at a refinery. Compressors are often powered by electric motors but can be powered by natural gas or refinery product gas. Gas combustion emissions consist primarily of hydrocarbons and sulfur oxides, the level of which will depend on the gas's sulfur content. Boilers are usually powered by oil or gas from the refinery and primarily generate sulfur oxides, nitrogen oxides, and particulates. The emission of nitrogen oxides from boilers can be reduced by using biased firing or staged firing. Biased firing uses various mixtures of air and fuel in different burners. Staged firing burns fuel-rich mixtures first, then injects air above the burner's flame to ensure more complete combustion. Fuel combustion by employee automobiles and by the tank trucks and tankers used to transport refinery products and crude oil will add carbon monoxide, hydrocarbons, and nitrogen oxides to the air at and near the refinery.

Valve and seal leakage and the evaporation of hydrocarbons will occur at all stages of the refining process, particularly at those stages which require high pressures and which transfer fuel from storage tanks to tankers, trucks, and rail cars. The combined average emission of hydrocarbons from various valves and seals is about 61 pounds per 1,000 barrels of oil processed (NERBC, Factbook, p. 6.26). The most effective means of controlling these emissions is a well structured maintenance program.

Sulfur dioxide, particulate, and carbon monoxide emissions from coking units are currently regulated by the federal government. In addition to meeting these "source" emission standards, a new refinery must obtain a federal air quality permit. Approval of this permit is contingent on the

Table 10
Emissions from Coking and Catalytic Cracking Units With and Without Electrostatic Precipitators and CO Boilers

(lb/1,000 barrels processed)

	Particulates	Sulfur Oxides	Carbon Monoxide	Hydrocarbons	Nitrogen Oxides	Aldehydes	Ammonia
Fluid Catalytic Cracking Units							
Uncontrolled	242	493	13,700	220	71	19	54
With Electrostatic Precipitators and CO Boiler	48	493	trace	220	71	19	54
Moving Bed Catalytic Cracking Unit	17	60	3,800	87	5	12	6
Fluid Coking Unit							
Uncontrolled	523	N/A	trace	trace	trace	trace	trace
With Electrostatic Precipitators and CO Boiler	7	N/A	trace	trace	trace	trace	trace

SOURCE: NERBC, Factbook, p. 6.21 (data from EPA).

Table 11
Emissions from Boilers and Compressors

(lb/1,000 barrels of oil burned and
lb/1,000 cubic feet of gas burned)

	Particulates	Sulfur Oxides	Carbon Monoxide	Hydrocarbons	Nitrogen Oxides	Aldehydes	Ammonia
Boilers and Process Heaters							
Oil-fired	840	6,720	trace	140	2,900	25	trace
Gas-fired	0.02	2	trace	0.03	0.23	trace	trace
Compressors							
Gas-fired	trace	2	trace	1.2	0.9	0.1	0.2

SOURCE: NERBC, Factbook, pp. 6.21-6.22 (data from EPA).

region still being able to meet National Ambient Air Quality Standards once the refinery is in operation. It may be difficult for the refinery to obtain a permit and locate in a community where air quality standards are barely being met or are already exceeded.

Water Requirement -- Refineries are major consumers of water. Water use depends on a refinery's capacity, the complexity of its product mix, processing and cooling system technology, and the quality of intake water. Refineries which produce relatively higher proportions of gasoline and other light distillates will require more water than refineries which produce relatively higher proportions of heavier fuel oils. A 250,000 barrel-per-day refinery may require up to 15 million gallons of water each day. About five million gallons per day may be lost through evaporation and not returned to the intake stream (NERBC, Factbook, p. 6.14). Gulf Oil's Alliance Refinery, which processes 200,000 barrels per day, uses 28 million gallons of water per day, four million of which are lost to evaporation (Clark et al., Recovery Technology, p. 183). Water for coastal refineries is typically drawn from nearby bodies of water and treated before being piped to processing equipment and cooling systems. Air cooling and closed-cycle water cooling systems can reduce a refinery's water requirement; however, these methods are energy-intensive, expensive, and not considered practical on a large scale (NERBC, Factbook, p. 6.14).

Wastewater -- Water pollution sources at a refinery include cooling water, process and boiler water, sewage, and site runoff. The magnitude and severity of the environmental impacts of wastewater discharges will depend on the physical and chemical characteristics of the crude oil and refinery products, the plant's capacity and design, and the sensitivity of nearby aquatic environments.

Cooling water constitutes the largest portion of the wastewater discharged from a refinery. Closed-cycle cooling systems and cooling towers can recycle clean intake water up to five times before discharging it. The cleaner the intake water, the more times it can be recycled; the water must eventually be discharged because repeated evaporation of some of the water increases the concentration of dissolved and suspended solids contained in it. "Once-through" cooling systems use much larger volumes of water and thus produce larger volumes of wastewater. In addition to heat, cooling water contains chemicals (chromate, zinc, and chlorine) which are added to intake water to prevent corrosion and fouling within the cooling system. High concentrations of these chemicals may prove toxic to aquatic organisms. Cooling water may also be contaminated by oil due to leaks in the cooling system. Federal regulations under the National Pollutant Discharge Elimination System (NPDES) set maximum pollutant concentrations for wastewater effluent from a refinery. Federal regulation also controls a refinery's thermal discharges; a company may exceed thermal discharge standards if it can show that the discharge causes no appreciable harm to the aquatic environment.

Process and boiler water may be the most contaminated wastewater stream discharged by a refinery. Pollutants are added to process water streams during various distillation, treatment, catalyst regeneration, and vessel cleaning operations. Table 12 gives a list of process water contaminants and the range of concentrations at which they might appear; wastewater discharges at the upper concentrations would not currently be allowed in an NPDES permit. More complex refineries, which produce larger proportions of gasoline and other light distillates, generate higher effluent concentrations. The water used in boilers is often treated with biocides and heavy metals to reduce corrosion and sludge in the boiler system; these chemicals may prove toxic to aquatic organisms when the water is discharged. Process water discharges can be treated by settling, filtration, biological, and chemical methods to remove suspended and dissolved solids, oils, and other contaminants.

Table 12
Process Water Contaminants

Pollutant	Concentration Range (parts per million)
Floating and dissolved oil	1 - 1,000
Suspended solids	not available
Dissolved solids	0 - 5,000
Phenol and other dissolved organics	0 - 1,000
Cyanide	0 - 20
Chromate	0 - 60
Organic nitrogen	0 - 50
Phosphate	0 - 60
Sulfides and mercaptans	0 - 100

SOURCE: NERBC, Factbook, p. 6.33 (data from EPA).

Stormwater runoff from the refinery site may also carry hazardous chemicals, organic matter, and sediments into adjacent waterways. Dikes around processing units and storage tanks contain site runoff and can channel it to holding ponds or tanks, where it is stored awaiting treatment and discharge. Current federal regulations limit the concentrations of total organic carbon, oil, and grease which may be present in runoff from petroleum storage sites. Contaminated runoff may be treated by separate facilities or at the same facilities as cooling water and process water.

The volume of sewage generated by a refinery will be large, relative to the volume produced by other oil and gas facilities, due to the number of people who work there. Sewage from a refinery may be treated by an on-site package treatment plant or connected to a municipal wastewater treatment system.

Wastewater from a refinery is typically discharged into nearby surface waters after being treated at on-site facilities. The effects of wastewater discharges on receiving waters will depend not only on the composition of the wastewater stream but also on the characteristics of the receiving body of water (its flushing rate, pH, animal and plant types, etc.). All new refineries must obtain an NPDES permit under the Federal Water Pollution Control Act; permit approval requires compliance with state and federal water quality and effluent standards.

Solid Waste -- The solid wastes generated by a refinery fall into three categories: processing residues, wastewater treatment residues, and general waste. The type and quantity of solid wastes depends on the volume and characteristics of the crude oil and the methods used to refine and treat it. Much of the solid waste will be contaminated by oil and hazardous substances and require special handling and disposal procedures. Refinery wastes should cause no serious environmental consequences if adequate treatment and disposal facilities exist at the refinery and in the surrounding community.

Processing residues include various sludges and sediments that are removed from or settle out of the product stream during gravity separation, refining, treatment, and storage. These residues are typically contaminated with oil and other hydrocarbons, sulfides, iron compounds, copper compounds, fluorides, calcium, and other chemicals.

Wastewater treatment residues come from the various treatment methods used at a refinery to remove solids and dissolved substances from process water, cooling water, and site runoff. These residues typically contain oil, calcium compounds, aluminum compounds, flocculants, biological sludges, and other chemicals.

General waste comes from various sources. It includes (1) wastepaper, bottles, cans, and food from throughout the yard, (2) packaging materials, such as crates, cardboard boxes, canisters, and drums, (3) wood, metal, and other scraps from construction and maintenance activities, and (4) ashes from boilers and other processing equipment.

Ocean dumping, deep well injection, and evaporation ponds were commonly used in the past to dispose of refinery wastes; current regulations tend to restrict the use of these methods because of the risk of environmental contamination that they present. Solid wastes are usually transported to landfills; fluidized bed incineration may be used to reduce the waste volume and burn off volatile compounds before the waste is delivered to the landfills. Landfills handling refinery wastes should be well designed to prevent contamination of ground waters, surface waters, and soils.

Noise -- If uncontrolled, the equipment at a refinery can generate high noise levels ranging from 80 to 100 decibels, which is above ambient levels in most communities.

Heavy equipment used during the construction phase (over about three years) will generate similar noise levels. Noise levels will vary with the size and design of the refinery; the impacts of the noise will vary depending on the nature of surrounding land and water uses. The most disruptive noises at a refinery, above the average background noise, are intermittent and caused by pressure relief valves and the flaring of gas.

Noise at a refinery may be substantially reduced by installing mufflers on and enclosing compressors, distillation units, and other refinery equipment. Most refineries maintain wide buffer zones around processing equipment; this helps decrease the carryover of noise to adjacent properties. A modern refinery using the best available technology should be able to keep noise at or below 50 decibels at its boundary (NERBC, Factbook, p. 6.43).

Aesthetics -- Storage tanks, large processing units, cooling towers, 24-hour lighting, and odors at a refinery may disrupt the aesthetic qualities of the landscape depending on the nature of existing land and water uses. Refineries usually have ample buffer zones which may reduce a facility's visual impact, especially when a buffer zone is combined with appropriate landscaping.

Oil Spills and Safety Hazards -- The large volumes of crude oil and refinery products stored and processed at a refinery create a substantial danger of fire, explosion, and spills. Even though refineries have a low risk of explosion and fire, the potential magnitude of damage is very high. Escaping vapors and liquids increase the chances of fires and explosions. Catastrophes are less likely if equipment at the refinery is routinely inspected and maintained and plant design and construction follows appropriate codes and industry standards. Refineries have extensive precautionary procedures and fire detection and extinguishing equipment. Processing and storage areas have complete water and foam extinguishing systems with portable dry powder extinguishers located throughout the site. Storage tanks often have individual foam systems which, when triggered, can rapidly cover an entire tank with foam. Berthside firefighting systems are usually self-contained and have a foam system and a water system, which may pump water directly from the harbor. The fire protection system at a refinery must meet the requirements of the National Fire Prevention Association and the U.S. Occupational Safety and Health Act as well as state and local fire prevention regulations.

Small spills of crude oil will occur periodically at marine oil terminals that are sited in conjunction with refineries. Little evidence currently exists on the impacts of continuous low-level concentrations of oil in aquatic environments. Large spills will occur less frequently but will receive major attention and may have significant short-term and long-term impacts on the aquatic environment. Coastal waters and wetlands typically contain dense plant and animal populations and serve as spawning and nursery grounds for waterfowl and marine animals. Environmental impacts can be severe when major spills concide with important breeding and growing seasons. The imapcts of major spills will be less severe in aquatic environments (such as urban harbors) which have already been altered by exposure to oil, industrial wastewater, and other discharges. Methods for containing and treating oil spills already exist; the key to minimizing the impacts of oil spills is rapid response. A good oil spill contingency program will have cleanup equipment readily available at the refinery terminal or at some nearby harbor facility and will swiftly put the equipment into operation at the first sign of a spill. Oil spill containment and cleanup is easier in waterways with slow currents and minimal wind and wave action.

FEDERAL ACTIVITIES AND THE FLOW OF INFORMATION DURING FIELD DEVELOPMENT

Development and Production Plans

An offshore oil or gas producer must conduct all field development and production activities in accordance with a Development and Production Plan that is approved by the federal government. The Plan identifies and describes all activities proposed by the lessee in a specific lease area and over a specific time period (up to and including sustained commercial production). The Plan must include:

1. a specific description of the work to be performed
2. a description of any drilling vessels, platforms, pipelines, or other OCS facilities and activities related to the proposed development
3. the location of each well
4. up-to-date interpretations of all available geological data
5. a description of environmental safeguards to be implemented
6. a description of safety standards and the features to be implemented to meet those standards
7. the expected rate and time schedule (from commencement to completion) of field development and production activities
8. a statement regarding the general nature of information deleted by the company under the Freedom of Information Act for inclusion in non-proprietary copies of the Plan, and
9. other information as the Director of the USGS might require.

The lessee files the Plan with the USGS, whose Director deems the Plan submitted if it meets the agency's requirements. The USGS is the lead federal agency governing the approval of Development and Production Plans, with other federal agencies participating in the review.

Within ten days after the Plan is submitted, the Director of the USGS must publish a receipt notice in the Federal Register and send non-proprietary copies of the Plan to the governors and coastal zone management agencies of affected states. The executives of affected local governments may receive the Plan upon request to the USGS Director. Local governments, states, and coastal zone management agencies may have 60 days, from the time they receive the Plan, to submit comments and recommendations to the Director; local governments must forward their comments to the governor's office (OCS Coordinator) before submitting them to the USGS.

In evaluating a Development and Production Plan, the Director must consider the Plan's consistency with offshore lease provisions and various federal laws and regulations. The Director must accept the recommendations of the state government and may accept the recommendations of local governments if he finds that they provide for a reasonable balance between the national interest and the well-being of the affected communities. If the state's recommendations are rejected, the Director must send a written explanation for the rejection to the governor. States that are adversely affected by the decision may file a notice of appeal, with any supporting information, to the Director within 30 days after the decision is made.

Environmental Reports (Development and Production)

The lessee must submit an Environmental Report to supplement the information contained in the Development and Production Plan and to help assess the impacts of field development and production activities. The Environmental Report accompanies the plan through all review processes but is not subject to "approval" or "disapproval" beyond a determination of its completeness.

Current USGS guidelines normally require Environmental Reports to contain the following information:

1. a summary of the nature, scope, and timing of the proposed field development and production activities, including safety and monitoring systems and new or modified onshore facilities

2. a description of the affected natural environment and socioeconomic structure

3. a description of the expected direct, indirect, and cumulative impacts on onshore and offshore environments resulting from the activities proposed in the Development and Production Plan

4. alternative actions that would create a lower risk of environmental damage, and

5. unavoidable environmental damage.

This information may simply be included in the Environmental Report by reference from the Development and Production Plan or from other environmental reports, assessments, or impact statements that have already been prepared for the same geographic area. The USGS uses the Environmental Report in evaluating the Plan and preparing environmental assessments and impact statements, which are required by the National Environmental Policy Act (NEPA) before the USGS can approve the Development and Production Plan.

Local governments may submit comments on the Environmental Report with their comments on the Plan. The timing and standing of comments is the same for both documents. Since the Environmental Report identifies the likely environmental impacts of proposed field development and production activities, local governments can use the Report to review the Plan itself in order to begin planning for the onshore impacts which are likely to occur if the Plan is approved and implemented.

Environmental Assessments

The USGS prepares an Environmental Assessment for each Development and Production Plan to evaluate the likely impacts of the proposed activities and to determine if USGS approval of the Plan will constitute a major federal action requiring USGS to prepare an Environmental Impact Statement. In preparing the Environmental Assessment, the USGS draws heavily on the company's Development and Production Plan and Environmental Report and may include comments on the Plan and Report from federal agencies, state and local governments, and other interested parties. The USGS official preparing the Environmental Assessment is responsible for evaluating the accuracy and objectivity of the information in the Plan and the Environmental Report before incorporating it into the Environmental Assessment.

Current USGS guidelines normally require an Environmental Assessment to contain the following information:

1. a description of the proposed action
2. a description of the affected environment
3. environmental impacts of the proposed action
4. alternatives to the proposed action
5. unavoidable environmental damage
6. controversial issues surrounding the proposed action and the USGS's response to them, and
7. finding of "No Significant Impact" or a determination that an EIS is necessary.

In addition to using industry information, the USGS may consult with federal, state, and local agencies with relevant responsibilities or technical expertise. The USGS begins preparing the Environmental Assessment when the company submits its Plan and Environmental Report. The Assessment must be completed before the Plan is approved and within 60 days of the last day USGS accepts comments on the Plan.

Local and state comments on the company's Plan and Environmental Report should appear in the Environmental Assessment; major objections, conflicting viewpoints, and the USGS's response to them will appear in the section on controversial issues. Local officials may, upon request, receive copies of the completed Environmental Assessment from the USGS.

Environmental Impact Statements

The USGS must prepare Draft and Final Environmental Impact Statements if the Director, after evaluating the Environmental Assessment, determines that approval of the Development and Production Plan constitutes a major federal action significantly affecting the quality of the environment. The Environmental Impact Statement will include:

1. a summary
2. the purpose of and need for the proposed action
3. a description and evaluation of the proposed action and alternatives
4. a description of the affected environment, and
5. a description of expected environmental consequences.

The USGS first prepares the EIS and circulates it for review in draft form. The USGS must send copies of the Draft EIS to the governors and coastal zone management agencies of affected states and, upon request, to affected local officials. The USGS must also make the EIS available to regional agencies and the general public. The review period for a Draft EIS is generally about 45 days, during which any interested party may submit comments to the USGS. The USGS may decide to hold public hearings, with the Draft EIS made available to the public at least 15 days beforehand.

In the Final EIS, the USGS must respond to all substantive comments received on the Draft EIS during the review period. The Director of the USGS must decide to approve or reject the Development and Production Plan within 60 days after the release of the Final EIS.

Local governments have no direct role in the preparation and evaluation of an Environmental Impact Statement. They may review and comment on the Draft EIS and participate in the initial "scoping" process. After its initial decision to prepare an EIS, the USGS must invite appropriate federal, state, and local agencies and other interested parties to participate in the "scoping" process. "Scoping" determines the range of actions, alternatives, impacts, and special issues which the Draft EIS is to present and analyze. Comments on the Draft EIS must be specific and address either the adequacy of the EIS or the merits of the alternatives it presents.

Consistency Certification

If the state wishes to review OCS field development and production activities for consistency with its coastal area management program, the state's CZM program list must refer to the various plans and permits that the federal government requires of the offshore oil and gas industry. These include Development and Production Plans, Section 10 permits, and NPDES permits. Lessees must then submit consistency certificates for state review when they submit plans and permit applications for activities which may affect the state's coastal region. State review begins when the state receives the lessee's consistency certificate, Development and Production Plan, permit applications, and other supporting information from the USGS Director or from the appropriate federal permit agency (such as the Corps of Engineers).

Consistency certificates generally have the following form:

> The proposed activities described in detail in this plan comply with (name of state)-approved coastal management program and will be conducted in a manner consistent with such program.

Applications for permits authorizing activities which OCS plans do not describe in detail (such as NPDES permits) are accompanied by consistency certificates of a slightly different form:

> The proposed activity complies with (name of state)-approved coastal management program and will be conducted in a manner consistent with such program.

The lessee must also provide the state with:

1. a brief assessment of the probable effects of offshore and onshore activities on the state's coastal area management program

2. a set of findings indicating that each of the proposed activities and facilities and their impacts are consistent with the state program's provisions, and

3. other information necessary for the state's consistency review.

Federal regulations encourage lessees to consolidate consistency certifications, supporting information, and the relevant plans and permit applications into a single package for state review. A lessee could submit one consistency certificate for the entire package (Development and Production Plan, NPDES permits, etc.). This helps minimize delays and gives reviewing agencies a comprehensive view of the proposed OCS operations.

If the state does not make a consistency determination within three months, either concurring or objecting, the federal government will assume concurrence unless the state requests an additional three months for review and gives reason for the delay. State concurrence with the consistency certificate is summarily assumed if the state makes no determination at the end of six months. The N.C. Office of Coastal Management must ensure timely public notice of the proposed activities, make the certification and accompanying information available for inspection, and request comments from interested parties.

If the state concurs with the consistency certification for a plan or permit, the appropriate federal agency may approve that plan or permit unless the agency disapproves it on other grounds. Once the state concurs, the lessee does not have to submit additional certifications with future permit applications for activities covered in the Development and Production Plan (such as an Application for Permit to Drill). The lessee must submit copies of all such applications to the state so that the state can monitor activities covered by the consistency requirement.

If the state objects to the consistency certification of any or all proposed activities, it must submit reasons and supporting information to the appropriate federal agency explaining the activity's inconsistency with the state's coastal zone management program. Upon receiving a state objection, federal agencies may not issue a permit or license until the objection is resolved, either through modification of the proposed activity or by the lessee's appeal to the U.S. Secretary of Commerce. The state has three months to review any modifications for consistency. The lessee has 30 days after it receives the state's initial objection to appeal to the Secretary of Commerce.

The state's objection to one or more activities in a Development and Production Plan does not prevent the lessee from obtaining federal approval of other activities which the state finds to be consistent. If the lessee submits a single consistency certification package for a Development and Production Plan and various federal permits, the state's objection to one element of the package does not prevent the lessee from receiving federal approval of the other elements.

NPDES Permits

The National Pollutant Discharge Elimination System, established by the Clean Water Act, requires the lessee to obtain an NPDES permit authorizing the discharge of effluents from an OCS-related facility into surrounding waters, subject to certain terms or conditions. The permit (1) sets numerical limitations on the discharges, based on EPA's effluent guidelines for the oil and gas extraction industry, and (2) outlines requirements for monitoring discharges and reporting to EPA the actual volumes discharged and any permit violations. Permits generally last for five years; the lessee must apply to EPA for a new permit before the existing permit expires.

The lessee must apply to EPA for the permit at least 180 days before the intended discharge. The permit application includes information on the applicant, the type of operation involved, the sources and nature of discharges, and proposed effluent treatment and abatement procedures. After assessing the application, EPA tentatively decides to approve the permit, approve it with modifications, or deny it. If the permit is approved, EPA issues a public notice of the draft permit, with copies sent to state fish and wildlife agencies, to other appropriate state agencies, and, upon request, to local governments and interested individuals. The public notice includes (1) a brief description of the location and nature of the proposed discharge, (2) the name and address of the office processing the application, (3) the location of the administrative record and the times it is available for public inspection, and (4) the name of a person, address, and telephone number where interested parties may obtain more information.

The public or any state or local government agency has 30 days after the permit is issued to submit written comments to EPA or to request that EPA hold a public hearing, stating the issues to be raised at that hearing. A public hearing may be held if EPA determines that a significant degree of public interest exists. EPA must issue a public notice of the hearing at least 30 days before the hearing. Any person present at the hearing may submit oral and written testimony. EPA may issue a final permit after the close of the comment period and then notify the applicant and each person who submitted comments or who asked to be notified.

Any interested agency or person may also request an evidentiary hearing to reconsider the terms of the permit and to discuss any legal or factual questions related to it. If EPA decides to hold the hearing, it issues a public notice, accepts requests to participate in the hearing, and accepts comments from the parties involved. The EPA Regional Administrator or the hearing's presiding officer issues a recommended decision on the permit after the evidentiary hearing. This decision becomes final unless it is appealed to the EPA Administrator or the Administrator elects to review it. Denials of evidentiary hearings may also be appealed to the Administrator.

Local governments may participate in the NPDES permit process at any point which provides for public participation. States with federally approved coastal zone management programs which mention NPDES permits in their program lists may review draft permits for consistency with the state's coastal management program objectives.

Corps of Engineers Section 10 Permits (Department of the Army Permits to Perform Work In or Affecting Navigable Waters of the United States)

Department of the Army permits are required (1) under Section 10 of the Rivers and Harbors Act for all structures or work in or affecting the navigable waters of the United States and (2) under Section 4 of the OCS Lands Act of 1953, as amended, for artificial islands and all installations or devices permanently or temporarily attached to the seabed on the outer continental shelf. The lessee must file a permit application with the Corps of Engineers for the construction and operation of offshore structures and equipment. Within 15 days of receiving the application, the Corps issues a public notice and circulates it to a wide audience (including appropriate local, state, and federal agencies and business and environmental groups) for review and comment. The notice may be published in local newspapers if the Corps's District Engineer expects a high level of public interest.

The public notice should include the following:

1. the name and address of the applicant and the location and description of the proposed activity
2. a plan and elevation showing site location and the character of activities, including the relationship of proposed structures to the size of the affected waterway and depth of water in the area
3. a list of other government authorizations obtained or requested
4. a preliminary determination of the need for and/or availability of an environmental impact statement, and
5. any other available information which may help in evaluating the proposal.

The Corps's District Engineer generally accepts comments for 15 to 30 days after the notice is issued. The District Engineer is to consider these comments in all subsequent actions taken on the permit application (such as deciding if a public hearing should be held or other federal agencies should be consulted).

When offshore facilities are to be constructed on lands under lease from the Bureau of Land Management, the BLM, in cooperation with other agencies, is presumed to have already evaluated the potential effects of the offshore facilities and activities on the total environment. The Corps will therefore limit its evaluation to the proposed activity's impact on navigation and national security. When offshore facilities (such as a pipeline) are to be constructed within the three-mile limit, the Corps is responsible for a full environmental review of the permit application, probably drawing on Environmental Assessments and Environmental Impact Statements previously prepared by the USGS for the same activity.

Local and state agencies will receive public notices of permit applications and may submit written comments to the District Engineer. When the proposed facilities and activities are located outside the three-mile limit, the Corps will refer to the Department of the Interior all state and local concerns beyond the scope of navigation and national security.

Corps of Engineers Section 404 (Dredge and Fill) Permits

Any activity which involves the discharge of dredged or fill material into coastal or inland waters and adjacent wetlands must obtain a permit from the Army Corps of Engineers as authorized by Section 404 of the Clean Water Act. Although closely related to the traditional Section 10 permit for dredging, filling, and channelization in navigable waters, the Section 404 program is much broader; it applies to all waters of the United States and encompasses more public interest evaluation criteria.

State Dredge and Fill Permits and CAMA Major Development Permits (see Appendix C) are closely coordinated with Corps permits by the N.C. Office of Coastal Management. The developer may submit a single joint application for Corps permits and the related state permits to either the Corps of Engineers' district office or the N.C. Office of Coastal Management's field office (see Appendix D). The Corps's Wilmington District recently developed a general Section 404 permit for projects in North Carolina's 20-county coastal area. Projects which receive state approval through a CAMA major development permit or a state dredge and fill permit will automatically receive a general Section 404 permit. Projects which would not require separate federal authorization include (1) maintenance of existing projects and (2) some new project, such as boat channels, bulkheading, canals, and cable and pipeline corssings.

Certain projects are not eligible for the General Section 404 permit and must apply for an individual Section 404 permits. Projects requiring separate federal authorization include those which have significant environmental impacts, involve unresolved state and federal agency conflicts, would adversely affect endangered species habitats or sites listed in the National Register of Historic Places, or would adversely affect designated wild and scenic rivers. If the project is determined to have a potentially significant impact on the environment, the Corps may have to prepare an environmental impact statement. This determination usually occurs during a pre-application meeting and site visit. Review and comment procedures for individual Section 404 permits are similar to those for Section 10 permits.

Applications for Permits to Drill

The lessee submits its application for a drilling permit to the USGS Area Oil and Gas Supervisor, who reviews the application and sends a copy to each affected state. The application must include:

1. the well's surface location and projected bottom hole location
2. the estimated depth of the well and depths at which oil, gas, water, and other mineral deposits are expected
3. the proposed casing and blow-out prevention program, and
4. any other required data.

This information must be consistent with the approved Development and Production Plan; it is not subject to a separate consistency review by the state government. Drilling may begin once the application is approved by the USGS.

Local and state comments on the permit application are not invited by the USGS. Local governments and other interested parties will have already reviewed the proposed drilling in their review of the Development and Production Plan.

Pipeline Permits

The lessee's field development and production plans may include proposals for pipelines to carry oil or gas from offshore platforms to onshore facilities. Many federal agencies are involved in the pipeline permitting process; state and local agencies become involved when the pipeline enters state jurisdiction (the three-mile limit) and comes ashore. The responsibilities of the federal agencies vary significantly and cover different aspects of the pipeline system. The USGS regulates rights to use the pipeline and its offshore right-of-way. The Bureau of Land Management approves the selected offshore right-of-way. The U.S. Department of Transportation's Office of Pipeline Safety regulates pipeline design, construction, and operation. The Federal Energy Regulatory Commission certifies gas pipelines. The Corps of Engineers issues Section 10 and Section 404 (dredge and fill permits) for pipeline installation. Each agency conducts its own permit procedures; there is little room for local or state input when the pipeline is beyond the three-mile limit.

Local and state control over pipeline location and installation practices become very strong once the pipeline enters the state's territorial waters and comes ashore. Local and state control in this area may be indirect (commenting on the permit conditions or decisions of federal agencies) or direct (regulating the location and operation of the pipeline and related onshore facilities).

OCS Air Quality Regulations

Regulations promulgated under the OCS Lands Act Amendments require offshore activities which significantly affect onshore air quality to comply with national ambient air quality standards. The Department of the Interior has authority to regulate offshore air emissions only if those emissions significantly affect onshore air quality. In its Environmental Report accompanying the Development and Production Plan, the lessee must determine which emissions will significantly affect onshore air quality and propose the type of control technology, if required, that the lessee will use.

In regulating offshore air emissions, the USGS has developed formulas for determining whether onshore air quality is significantly affected by offshore activities and for determining whether offshore activities are exempt from air quality regulations. These formulas are usually based on emission rates at the facility and the facility's distance to shore. When an offshore facility is subject to air quality regulations, the lessee's Environmental Report must include emission and distance-to-shore data, meteorological data, an explanation of models used to derive the data, and a description of the control technologies and emission monitoring programs to be implemented. The USGS reviews and approves the lessee's air quality control program as part of the related Development and Production Plan; no additional air quality permits are required of offshore facilities.

Participation in OCS air quality regulations rests more with state agencies than local agencies. Participation can take several forms. In reviewing the company's Development and Production Plan and Environmental Report, state and local agencies may review and comment on air emissions and other data and the company's proposed control technology. Onshore air quality impacts may be considered in the state's consistency certification procedures. If the state offers evidence that emissions from an exempted offshore facility will indeed affect onshore air quality, then the USGS Director may require the oil company to submit additional information to determine if control measures are necessary.

Oil Spill Prevention, Control, and Cleanup

The prevention of oil spills resulting from OCS field development and production is currently regulated by the USGS, which outlines requirements for drilling procedures, blowout prevention equipment, and related activities or equipment. A lessee must submit an oil spill contingency plan to the USGS as part of its Development and Production Plan. The oil spill contingency plan details the procedures, personnel, and equipment to be used by the company for the prevention, report, and cleanup of oil or other waste spills during field development and production. The contingency plan includes:

1. an assurance that full oil spill response capacity is known and can be committed to oil spill control, including an inventory of available cleanup equipment and materials

2. procedures for early detection of an oil spill and notification of appropriate parties, including a list of responsible cleanup personnel and regulatory agencies

3. well-defined actions to be taken upon detection of an oil spill, and

4. provisions for the disposal of recovered spill materials.

Interested parties may review and comment on the oil spill contingency plan as part of their review of the related Development and Production Plan.

In addition to the oil spill contingency plans required of offshore operators by the USGS, the U.S. Environmental Protection Agency, under the terms of the Clean Water Act, requires the owners or operators of certain onshore oil storage facilities to prepare a Spill Prevention, Control, and Countermeasure Plan (SPCC Plans). The regulations for SPCC Plans apply (1) to above-ground storage facilities with capacities of 1,320 gallons or more and (2) to below-ground storage facilities with capacities of 42,000 gallons or more. An SPCC Plan must be certified by a registered engineer and implemented by the owner or operator of the storage facility. EPA does not review SPCC Plans for approval unless a spill of more than 1,000 gallons occurs at the facility or two spills of any size occur within a one-year period. In either case, the owner or operator must submit to EPA the original SPCC Plan, an analysis of why the plan failed, and an amended plan. EPA reviews these documents and either approves or disapproves the amended plan.

If a spill or blowout does occur at an offshore platform or onshore facility, the facility's owner or operator must contain and clean up the spill in accordance with its previously approved contingency plan. The USGS monitors control measures performed at and within 500 meters of the offshore well site. Cleanup measures outside that radius (such as in harbors) are monitored by an On-Scene Coordinator designated by the U.S. Coast Guard. A Regional Response Team, representing federal, state, and local organizations and chaired by the Coast Guard, will be available to the On-Scene Coordinator for advice and Guidance.

The On-Scene Coordinator and Regional Response Team are to develop local and regional contingency plans, if necessary, to supplement the operator's oil spill contingency plan. Regional plans are broad in scope and include information on all cleanup facilities and other useful resources in the region. Local contingency plans cover each On-Scene Coordinator's area of responsibility and outline in detail the response to a spill in that area. Local contingency plans must identify:

1. environmentally sensitive areas and the most probable location of oil spills

2. the resources that would be needed to respond to oil spills and the location of such equipment and manpower

3. plans of action for protecting particularly vulnerable natural resources

4. sites for disposing the recovered oil or hazardous substances, and

5. a local organizational structure for responding to oil spills.

OCS Oil and Gas Information Program

The USGS's OCS Oil and Gas Information Program requires lessees to provide the agency with access to information from offshore exploration, development, and production activities. The USGS uses this information to prepare two documents, a Summary Report, and an Index, which it submits to state agencies and, upon request, to local governments. The documents are to aid local and state agencies in planning for the onshore impacts of offshore activities and in reviewing Development and Production Plans and other documents.

The Summary Report provides up-to-date information on the actual level and pace of OCS activity in the leasing region. USGS prepares separate reports for each region (South Atlantic, Mid-Atlantic, Gulf of Mexico, etc.). The Summary Report describes current activities and predicts potential activities and impacts over the following six months. USGS updates the report about every six months. If significant events occur in the region, such as commercial discoveries or the submission of development and production plans, then the USGS will issue a new Summary Report. The contents of the Summary Report may include:

1. estimates of oil and gas reserves and resources and, when available, projected rates and volumes of oil and gas to be produced from leased areas
2. magnitude and timing of offshore activities
3. methods of transportation to be used and approximate routes to be followed, and
4. general location and nature of near-shore and onshore facilities expected to be utilized.

USGS issued the initial Summary Report for the South Atlantic region in July 1980; its first update was issued in February 1981 (see Appendix A, Section III - "Regional Information").

The Index lists all plans, programs, reports, and studies relating to offshore development in the leasing region that have been prepared by or received by the USGS under the provisions of the OCS Lands Act Amendments. The Index contains separate sections for each document generated in the OCS decision-making process (Exploration Plans, Development and Production Plans, Drilling Permits, Environmental Assessments, etc.). Each section describes the document in general, shows its timing in relation to other documents, and lists (by lease sale number) all such documents that have been prepared to date. The USGS will update the Index annually if a significant level of activity occurs in the region; the USGS issues a memorandum approximately every six months which indicates the status of OCS activities and lists new documents which will appear in a forthcoming edition of the Index. Affected local and state agencies may request copies of all documents listed in the Index except those which contain confidential proprietary information. The Department of the Interior published the Atlantic Index in May 1979 (see Appendix A, Section III - "Regional Information").

Site-Specific Transportation Studies Plan and Regional Transportation Management Plan

The Bureau of Land Management's Intergovernmental Planning Program (IPP) encourages cooperation between the major participants in OCS decision making (federal agencies, state governments, industry, and other affected parties) through membership in the Regional Technical Working Group (RTWG). North Carolina is a member of both the South Atlantic RTWG and the Mid-Atlantic RTWG. The Group's activities during the field development stage focus on making recommendations to the federal government regarding the transportation of oil and gas to shore.

The Regional Technical Working Group will prepare a Site-Specific Transportation Studies Plan (Phase III of the IPP) if and when marketable oil or gas reserves are discovered in the leasing region. The Site-Specific Transportation Studies Plan identifies the information needed for siting pipeline corridors and onshore facilities. This information may come from studies generated by BLM's Environmental Studies Program or other federal and state programs.

The Working Group will prepare a Regional Transportation Management Plan (Phase IV of the IPP) as soon as it completes the Transportation Studies Plan. Phase IV should be completed before an offshore lessee submits a Development and Production Plan. The Regional Transportation Management Plan will contain:

1. recommendations for specific pipeline corridors
2. alternative sites for related onshore facilities
3. tanker or other surface transportation alternatives
4. plans for monitoring the construction of oil and gas transportation facilities, and
5. any stipulations the Group deems appropriate.

A draft of the plan is made available for public review, after which it may be revised in response to any comments received by the Working Group. The Working Group submits the final plan to state officials, BLM, and USGS for their planning purposes. Local governments may receive copies of the plan upon request.

All Working Group efforts are not binding decisions, but are recommendations to BLM which aid it in pipeline corridor siting and its other offshore decisions. The Working Group's recommendations, because of their depth of analysis and the variety of viewpoints they represent, often give decision makers in the Department of the Interior the best information available upon which to base their decisions.

The Production Stage

The production stage begins when offshore platforms, transportation systems (pipelines and/or tanker terminals) and onshore facilities are in place and oil and gas are brought to shore and processed. Production is likely to overlap with exploration and field development; exploratory drilling and field development can continue in other parts of the leasing region once the first production platforms are in place.

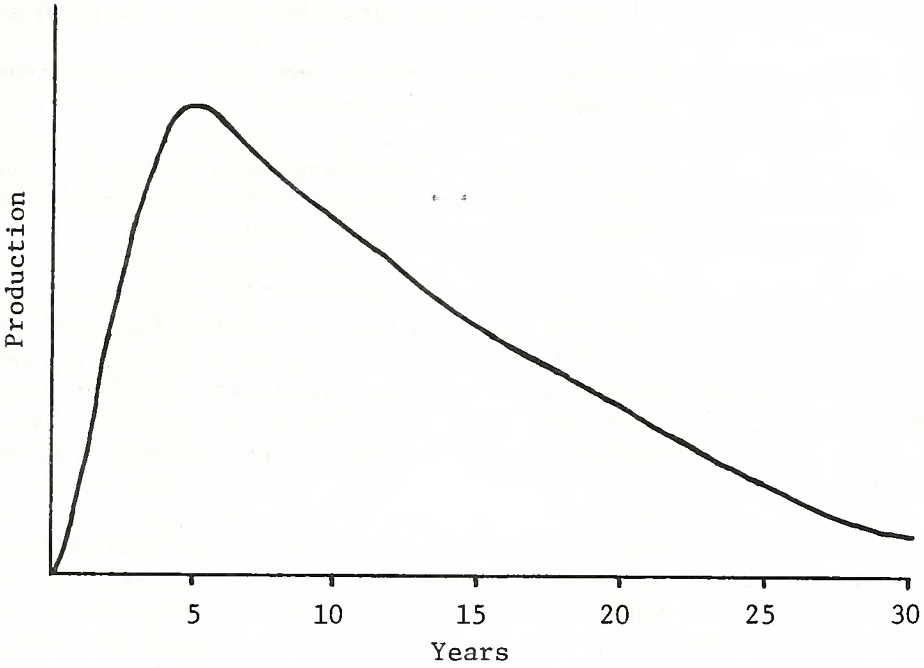
Oil and gas production from an offshore field may last from ten to over 25 years depending on the size of the field, the industry's rate of recovery, and the capacity of the transportation system. Production levels from an individual field or reservoir are an aggregate of production levels from several individual wells; production levels from the leasing region are an aggregate of production levels from individual fields. Production from the entire leasing region may last substantially longer than production from an individual field depending on the timing of subsequent lease sales and field development in the region.

Production from an offshore field peaks within the first four to five years as new wells are gradually drilled and put into production. After about five years, production steadily declines over the economic life of the field as it becomes more costly and technically difficult to recover oil and gas from the reservoir (see Figure 34). Secondary and tertiary recovery techniques (such as fracturing and steam injection), which have been developed to enhance extraction rates from oil and gas fields, may extend a field's economic life. The use and effectiveness of these techniques depends on their cost and the geologic characteristics of the reservoir.

Offshore activity during the production stage occurs at a much lower level than during field development. Offshore platforms house relatively small crews to monitor and maintain production and safety equipment; production technology is highly automated. Offshore activity may experience short-term increases to field development levels as (1) wells are repaired or "worked over" to maintain production rates, (2) secondary and tertiary recovery techniques are put into practice, and (3) new wells are drilled from a platform. At the same time, the offshore industry may carry out additional field development activities (such as constructing new platforms, pipelines, and storage facilities) when an oil and gas field shows a greater production potential than was previously expected.

Onshore impacts, which begin in the exploration stage and reach a crescendo during field development, change in character in the production stage. As onshore facilities are put into operation, the large number of workers used to construct them must move elsewhere or find different jobs within the

Figure 34
Timing of Production from a Typical Offshore
Oil and Gas Field



community. Onshore employment encompasses "permanent" jobs at onshore facilities; permanent employment will be substantially less than construction employment. Many of these production jobs will go to specially skilled workers from outside the region who will move to the coastal communities where production facilities are located. Some workers may be recruited from the community's existing labor pool and trained for oil and gas jobs. Jobs which are less specialized and require fewer skills will draw more heavily on the existing local workforce.

Impacts on the overall economy and fiscal health of the community are less predictable. Oil and gas production may attract new businesses to the community and stimulate existing businesses. These businesses can range throughout all sectors of the local economy, from selling supplies and services to offshore industry employees. However, onshore oil and gas activities may repel other businesses, especially in recreation and tourism, if oil and gas facilities are not properly sited, monitored, and managed.

The production stage creates the greatest potential for local fiscal benefits once onshore facilities are operating and taxed and the size of the construction workforce (and its demand for public services) has declined. Revenues from onshore production facilities may or may not offset the costs of supplying public services to the construction (or field development) workforce and to the production workforce. The net fiscal impact of onshore oil and gas activities on a local government will depend on:

1. the magnitude of population increases and new service demands associated with the field development and production stages
2. the timing of new service demands and tax revenues from onshore facilities and their employees, and
3. whether or not the onshore facilities are located in and paying taxes to the local jurisdiction which is affected by the growth in population and public service demands.

Population increases and new service demands will have less of an impact on larger coastal cities which (1) have available skilled and semi-skilled labor to obviate some of the offshore industry's need to bring in outside workers, and (2) have adequate public service capacities and housing stocks to absorb the demands of new workers and their families. Small, rural coastal communities will find it more difficult to assimilate onshore development and the service demands it creates.

The timing of tax revenues and service demands is very important. The more that the field development and production stages overlap, the earlier will local governments be able to offset service costs with tax revenues from onshore facilities. If onshore and offshore employment and onshore public service demands reach a high level during field development, and production does not begin for several years, then the local government may not have revenues available when it most needs them.

In some cases, an onshore oil and gas facility will be located in one community or local jurisdiction while its workers live and use public services (schools, water and sewer, etc.) in another jurisdiction. When this occurs, the local government bearing the increased cost of public services is not compensated by increased revenues.

Federal government activities during the production stage focus on monitoring, inspecting, and regulating offshore operations and some onshore activities for compliance with national environmental, occupational safety, and interstate commerce policies. The federal agencies responsible for regulating the offshore oil and gas production system include the Environmental Protection Agency, the U.S. Geological Survey, the Occupational Safety and Health Administration, the Department of Transportation's Office of Pipeline Safety, the U.S. Coast Guard, the Interstate Commerce Commission, and the Federal Energy Regulatory commission. The Coast Guard carries primary responsibility for coordinating and implementing oil spill containment and cleanup efforts in conjunction with state and local agencies. State agency responsibilities during the production stage similarly focus on monitoring, inspecting, and regulating onshore and nearshore activities, especially to ensure compliance with state policies and programs to maintain water quality, air quality, and the quality of sensitive natural and cultural environments (areas of environmental concern).

Local government activities during the production stage will include some monitoring and inspection of onshore facilities by fire departments, public health departments, and other local agencies to ensure compliance with local environmental and public safety policies. Local police and fire departments can play an important role in oil spill containment and cleanup efforts as maintainers and operators of cleanup equipment and as members of the Regional Response Team chaired by the U.S. Coast Guard. Other local government activities with regard to onshore oil and gas facilities will concentrate on the taxation of onshore facilities and the provision of services to the oil and gas industry and its employees.

Local planners, citizens, and government officials should recognize that an onshore development boom may be short-lived if major oil and gas facilities (such as refineries) and related industrial development (such as petrochemical plants) do not locate in their community. The location of such major oil, gas, and related facilities probably has more to do with product markets and transportation economics than with production of oil and gas offshore. Some communities may prefer onshore OCS-related development to be minor and/or short-lived. Communities that want larger-scale or continuous development should plan early in the OCS development process for attracting more "permanent" oil and gas activities to supplement short-term field development and onshore construction activities. These communities should consider attracting other industries as well. The life of offshore oil and gas fields is shorter than the life of an established community; a diversified industrial economy will minimize depression of the local economy when offshore production declines.

The Shutdown Stage

Offshore fields eventually reach a point of economic exhaustion; substantial amounts of oil and gas that are not economically recoverable may remain in the reservoir. At this stage, oil and gas companies decommission and shut down offshore and onshore facilities. Wells are plugged to prevent pollution. Platforms are removed to eliminate navigation hazards. Pipelines are abandoned. Onshore facilities are abandoned, dismantled, or converted to other uses.

Shutdown activities may occur up to three years after offshore production ceases. The U.S. Geological Survey (USGS) normally requires all well casing or piping to be cut 15 feet below the sea floor and removed; the well must then be sealed with cement to prevent oil and gas leaks. The abandoned well site is dragged to remove any obstruction on the sea floor. Offshore platforms are dismantled and may be brought to shore as scrap metal. Pipelines are typically left in place after being flushed with water and cleaning agents to remove any residual hydrocarbons. After the connection between the platform and the pipeline is cut, the pipeline is sealed and left on the sea floor. The cost of removing a pipeline is generally higher than the pipe's salvage value. Partial processing facilities will be dismantled and scrapped. Onshore tank farms can be used to store oil from other sources but are also likely to be scrapped. Marine oil terminals may continue to receive crude oil and petroleum products from other sources or may be converted to handle other types of cargo. Service bases will be abandoned and may also be converted to handle other types of cargo. Gas processing plants may be salvaged, converted to process other gas streams or used to store gas and liquid hydrocarbons. Refineries will remain in operation but must rely more on outside sources of oil.

Onshore facilities used for exploration and field development may shut down much earlier, at the beginning of the production stage. Temporary service bases will be abandoned unless they are expanded into permanent bases serving field development and production. Pipe coating yards and installation support bases will be abandoned after offshore platforms and pipelines are in place.

The role of the federal government during the shutdown stage is primarily to monitor offshore abandonment activities and to enforce applicable regulations (such as those regarding navigational safety). The bulk of federal responsibilities falls on the USGS.

Local government faces the task of mitigating past onshore impacts, covering the loss of revenues from onshore oil and gas facilities, and maintaining the local economy in the face of declining employment. The shutdown stage can be as important as the other stage of OCS development. Since the economic life of offshore fields is limited, local governments must be prepared for the inevitable loss of jobs and related economic activity that OCS development may have generated. Local governments can plan well ahead of time to ease the adverse economic impacts of the shutdown stage. They can arrange for alternative uses of waterfront land, cargo facilities, and other sites abandoned by the oil and gas industry. The presence of other industries in the community and attracting new industries will help absorb or minimize the impacts of unemployment and decreased business activity. Larger coastal communities which have diversified economic bases should have little trouble coping with the shutdown stage. Smaller communities that have become more dependent on the offshore oil and gas industry will be more adversely affected.

CHAPTER FOUR: OPTIONS FOR LOCAL PLANNERS

Local influence over OCS development is greatest for onshore facilities. While these onshore facilities are only one part of the total offshore oil and gas production system, they are in direct contact with the community and its people. Local government actions on the location and construction of onshore facilities may determine the nature of the critical environmental, social, economic, and fiscal impacts faced by local residents. In North Carolina, local actions are taken within the framework of the Coastal Area Management Act.

Coastal Area Management Act

Under the North Carolina Coastal Area Management Act (CAMA), policies and regulations are provided to ensure that energy facilities locating in the coastal area are consistent with environmental preservation and economic development objectives, as well as with energy demands. Consistency provisions in the federal Coastal Zone Management Act require that all plans for exploration, development, and production from areas leased under the OCS Lands Act must carry a certification that they comply and will be carried out in a manner consistent with the state's approved coastal management program. The North Carolina Coastal Management Program has established the following criteria for judging the consistency of OCS development proposals with the state's coastal management objectives (Draft EIS on Amendments to the North Carolina Coastal Management Program, 1979, p. 90):

- Risks of environmental harm to fish spawning areas are assessed and minimized

- Risks of spills from OCS operations and possible trajectories are evaluated and appropriate mitigation measures employed

- Dredging, spoil disposal, and construction of structures is minimized. Any necessary action of this sort should minimize damage to the marine environment

- Potential damage or interference with traditional fishing grounds or areas with high biological/recreational value (reefs, rock outcrops) is avoided

- Placement of structures in geologically hazardous or biologically sensitive areas is avoided

- Potential wildlife destruction or relocation is assessed and minimized

- Planned onshore facilities conform to relevant policies enumerated in Section 3*

- Planned onshore facilities are in conformance with the appropriate local land use plan(s)

The North Carolina Coastal Management Program requires that any development proposed in a designated Area of Environmental Concern (AEC) must obtain a permit before proceeding. Since the designated AECs form a buffer zone around all coastal and estuarine waters, any OCS-related development within the state's territorial waters, marshlands, ocean hazard areas, etc. will require a permit. Two types of permits are used:

- Major development permits, issued by the Coastal Resources Commission, cover construction projects that: (1) have land or water areas of more than 20 acres or structures covering 60,000 square feet or more of ground area, (2) involve drilling or excavating for natural resources, or (3) require permission or licensing by a state agency other than the Coastal Resources Commission

- Minor development permits, issued by designated officials of local governments with jurisdiction over the area, cover all projects not defined as major developments.

Each coastal county must, and each municipality may, prepare a land use plan following Coastal Resources Commission guidelines. These plans must contain local land use objectives, policies, and standards for growth; supporting data on population and economic trends, and resource or environmentally sensitive areas; and land classification maps reflecting the desired urbanization pattern of the area over a ten-year period. Local governments may implement their land use plans in the manner that they choose; however, all local ordinances and regulations must be consistent with the local land use plan.

As of 1981, a coordinated federal-state-local coastal management system is operating in North Carolina to ensure that the impacts of offshore oil and gas development are carefully regulated. Should major changes be made in the federal programs or regulations affecting the coast and OCS development, these changes could place more responsibility on state and local governments in the future. This possibility makes it especially important for local governments to take an active role to prepare for the potential impacts of OCS development.

---

*Section 3: Coastal Management Policies includes state policies on energy generating facilities, petroleum refineries, the outer continental shelf, and mining. Stated policies require applicants for major energy facilities to submit impact assessments and to select inland sites unless shorefront access is necessary and to protect coastal waters and public access when shoreline locations are necessary.

Local Options

Four types of preparatory actions were described in Chapter II -- Preparing for OCS-Related Development: (1) understanding industry operations and government regulations, (2) establishing communications, (3) evaluating community capacity, and (4) setting up community policies and development guidance programs. Local governments have several options in following through on these preparatory actions. After briefly considering the first three steps, this chapter will focus on options for the fourth step.

Understanding the OCS Development Process

This guide provides the basic information on OCS development for local governments. After local planners and public officials have used the guide and other sources to gain an understanding of the basics of offshore industry operations and their impacts, and the federal and state regulatory process and the information it generates, then they need to educate their communities about these matters. The objective in following through on this preparatory step is to design and carry out an effective OCS public information program for community leaders and citizens at the local level. While such a program need not be elaborate, it should be well-planned.

Options for an OCS public information program include several elements that can be used singly or in combination at various stages of the OCS development process.

- News releases prepared by the local government after consultation with state government and/or industry officials can be used to announce important events and to provide factual background information through radio, television, and newspapers.

- Workshops or public forums which bring together OCS experts and local leaders can be used to highlight issues, problems, and opportunities in OCS development, as well as to brief the community on what to expect. Organizations like the League of Women Voters can assist in staging workshops and forums.

- Speakers from government and industry can be made available to civic groups and other organizations interested in learning about local implications of OCS development.

Because the potential spread of onshore impacts is broad, creating a well-informed community at the start may prevent problems due to misunderstanding later in the process.

Establishing Communications

Local planners and government officials must establish reliable contacts with federal and state OCS agencies and oil and gas industry representatives to ensure a continuous flow of information. If steps to develop these linkages have not been taken before the offshore oil and gas leases are sold, immediate moves should be made to correct this situation during the exploration stage. These direct lines of communication will help keep localities up-to-date on OCS activities and give planners, residents, and local officials important opportunities for input into federal and state permit processes.

The place to begin building contacts outside the local community is with state government officials responsible for coastal energy impacts and OCS development: (1) the Coordinator of the Coastal Energy Impact Program in the Department of Natural Resources and Community Development and (2) the OCS Coordinator in the Office of Marine Affairs, Department of Administration. Both of these officials have offices in Raleigh. (See Appendix D for contact information.)

These officials can ensure that the community is added to mailing lists for information and direct local planners to other appropriate state agencies, as well as to relevant industry groups, such as the North Carolina branch of the American Petroleum Institute or particular companies.

To establish a reliable communications channel within the community, a local OCS management coordinator should be designated as soon as it is clear that the community will likely be affected by offshore oil and gas development. This lead local OCS official could be a planner, a building official, an engineer, or a city or county manager. The point is to give federal and state agencies and private companies a consistent, reliable, and technically informed contact point in the local government. As the "bridge" between the locality and external OCS groups, the local OCS coordinator should be a person who understands offshore and onshore development, who knows the laws and regulations governing it, and who can channel messages to appropriate people both inside and outside the community.

Once a coordinator is designated, several communications options may be pursued:

- Technical OCS working groups can be formed of various local experts and government officials to ensure that those who need to know and to respond on technical matters are kept informed.

- OCS policy task forces can be formed of elected officials and community leaders to facilitate the flow of policy-related information to local decision makers.

- OCS depositories can be set up at city halls, county courthouses, public libraries, and/or Marine Resource Centers to collect and make accessible various reports and other OCS materials.

The level of effort needed for communications will vary from a single coordinator in a community expecting limited impacts to a full program of working groups, task forces, and depositories in areas facing large-scale onshore development.

Evaluating Community Capacity

OCS development is a two-way street. Local communities that want to share in the increases in oil and gas employment and economic development must be prepared to contribute to the needs of the oil and gas industry. Evaluation of a particular locality's capacity to serve the needs of the industry involves assessing both ability to contribute and desire to do so.

Ability to Contribute

Assessment of an area's ability to contribute is basically a matter of inventorying area resources which might be demanded by OCS development. Such an inventory should not be difficult to assemble. Much information probably is already available through economic development agencies, Chambers of Commerce, planning offices, utility companies, Port Authority offices, and area universities or community colleges.

Types of information needed include available port and harbor facilities, service base and terminal sites, marine repair yards, transportation facilities, labor force skilled in OCS work, and general support services. It is also useful to assemble data on cost and availability of public services such as water supply and waste disposal, on local taxes and development regulations, and on the local housing market. (See NERBC Factbook for discussion of types of information necessary.)

Desire to Contribute

Assessment of an area's desire to participate in oil and gas development is a more subjective matter. This involves airing the pros and cons of serving as a host community to the offshore oil and gas industry, and reaching agreement on the balance of costs and benefits to the host community. Each locality will have a different balance sheet, depending on its capacity to absorb potential boom and bust development cycles, the likely onshore facilities that it might receive, and its ability to manage large-scale development without overstressing its fiscal operations.

Plumbing the community desire to contribute can be done very informally, through conversations with local leaders and groups, or it can be done more publicly, through workshops or public forums with experts, government officials, and business and civic leaders exploring positive and negative aspects of likely community impacts. Another option would be to use technical working groups or policy task forces to review the issues and report to decision makers. If the outcome of these deliberations is positive, then the next step is to prepare policies and programs to guide development toward local goals.

Setting Up Policies and Programs

In most communities, new local policies and programs will have to be designed to manage OCS development impacts. As a frontier area, the North Carolina coast has not previously regulated OCS oil and gas development, so the only direct references to OCS policy goals and program criteria are in North Carolina Coastal Area Management Program documents. Affected local governments must decide on their public goals and then adopt local ordinances and other actions to carry out these goals.

Much of the work at this stage will necessarily have to be done by professional planners, who are familiar with land use and development management options. Their work can be reviewed by local OCS technical working groups and policy task forces, if they exist, and/or by the local government planning board and elected officials who will adopt the new management tools.

Existing Tools

The first step is to analyze all existing local policies, procedures, plans, and regulations in light of their adequacy to manage future OCS activities. While it is possible that existing management tools will be sufficient, the more likely outcome of this review will be a listing of gaps in the present system. Even though all coastal areas have land use plans, for example, some do not have zoning ordinances and other implementation tools. In addition, the broad land classification categories of these land use plans (developed, transition, community, rural, and conservation) may not be particularly useful for the specifics of managing OCS-related facility construction.

Community Objectives

The recommended second step is to prepare a set of community objectives for OCS-related onshore development. These should identify the community's position on such issues as land use, environmental quality, the local economy, municipal finance, and local government participation in commercial ventures. (A discussion of these issue areas, with examples of objectives and implementation strategies, has been provided in Chapter II, and an example of a policy statement from a California county is provided in Appendix B.) In some areas, it may not be possible to get local government approval of specific, written objectives; however, by attempting to draft objectives, planners can highlight critical issues.

New Management Tools

The next step is to review the various management tools available for guiding OCS-related development and to select those which are suitable for use in the local area. In addition to policy statements and land use plans, other types of management tools include land use and development management ordinances, lease agreements, and permit review procedures. Permit review procedures for state and federal OCS permits are discussed in Chapter III for the major stages of OCS development, and the relevant North Carolina environmental permits are described in Appendix C. Lease agreements are covered briefly at the end of this chapter. Most attention in the following sections is devoted to land use and development management ordinances, since they are the single most effective type of local growth management tool for dealing with impacts of OCS-related onshore facility construction and operation. Localities whose housing stocks or public services are adequate for demands of OCS-induced growth may also need to consider using other types of growth management tools, such as capital improvement programs or impact fees. (For a review of the full array of potential tools, see Brower et al., Growth Management in Coastal Communities.)

Land Use and Development Management Ordinances

The mainstay of local land use and development management ordinances is the zoning ordinance. To manage OCS-related development, coastal communities without a zoning ordinance will need to adopt one, and those with an existing ordinance will probably need to add new provisions. A good source of information for the OCS-related aspects of this task is Planning for Onshore Development: Discussion Papers prepared by the American Society of Planning Officials in 1977. This publication is drawn upon in the following discussion, and excerpts from its sample policies and ordinances are provided in Appendix B. The approach of this publication is to treat OCS-related onshore facilities as a special type of industrial development.

Six techniques are recommended for managing new OCS industrial developments:

1. Special Permits are documents issued after a process of government review, which require selected uses to gain administrative approval to locate in specific zoning districts. Uses requiring special permits are those that might not be compatible with uses permitted by right in the district. Issuance of the permit is based on a determination of compatibility of the proposed use. In the case of OCS-related facilities, special permits can be used to permit heavier industrial uses in industrial zoning districts and to permit OCS-related uses in non-industrial areas. Special standards for OCS-related facilities can be made a condition of permit approval, for such features as site plan modifications, facility operations, and provision of improvements.

2. Waterfront Industrial Districts are zoning districts used to set apart and protect areas vital to port functions, to exclude inappropriate uses, to preserve scarce waterfront land for water-transport or water-using industries that need it, and to protect fragile coastal resources from development when suitable inland sites are available. Water-dependent OCS-related facilities can be allowed by right or by special permit in Waterfront

Industrial Districts, including service bases, repair and maintenance yards, pipelines and marine terminals, platform fabrication yards, pipe-coating yards, and other support facilities that are water-dependent. Other facilities, such as partial processing facilities and gas processing plants, are not water-dependent. For an example, see the New Bedford, Massachusetts Waterfront Industrial District zoning ordinance section in Appendix B.

3. Planned Industrial Districts are "floating" zones similar to Planned Unit Developments, which are applied to areas rezoned at the request of a developer or as a community initiative, rather than being fixed on the original zoning map. Designed for industrial park type uses, these Planned Industrial Districts are written into the text of the zoning ordinance to allow flexibility in site location and design and to encourage unified development of large areas. Effective administration of Planned Industrial District provisions demands planning department staff expertise in negotiation, site planning, and impact assessment. This district would be used to encourage clustering of OCS-related facilities such as service bases, marine repair yards, and ancillary facilities, or to coordinate development of large facilities such as gas processing plants. See Appendix B for the Northampton County, Virginia Planned Industrial District, which is designed to control, through special conditions, the proposed platform fabrication yard in that county.

4. Industrial Performance Standards are provisions in an ordinance that indicate allowable levels of noise, glare, vibration, toxic matter, fire and explosion hazards, smoke, particulates, and odor from industrial uses. They are more flexible than lists of permitted uses for defining industrial districts because they regulate the effects of the industry on the environment. Establishment of performance standards is appropriate for OCS-related uses because of the many noxious or hazardous impacts from the industrial processes used.

5. Site Plan Review is a process which can be added to a zoning ordinance or adopted separately to require commercial and industrial developments and large-scale projects not involving land subdivision to submit detailed site plans. These plans are reviewed in accordance with development standards, public facility and service provision, and compatibility with adjacent uses. Site plan review is appropriate for all OCS-related facilities which usually require relatively large amounts of land and have distinctive site characteristics.

6. Local Environmental Impact Statements are disclosure documents, required of public and private developers, which must include information on the impacts of the development upon the environment. The North Carolina Environmental Policy Act of 1971 authorizes localities to require environmental impact statements from developers of major development projects, which include commercial, industrial, and residential projects of at least two acres. While few North Carolina areas have used this enabling authority, such statements might be useful in encouraging environmentally sound design of OCS-related projects. See the example Environmental Impact Statement ordinance from Troy, Michigan, in Appendix B, which includes impacts on public facilities and services.

The six techniques may be combined in various ways. For example, the Northampton County, Virginia Planned Industrial District ordinance includes industrial performance standards and site plan review procedures. Special permits can be used with industrial districts, performance standards, and site plan review; also, many of the other techniques can be used to supplement each other. These regulations, in combination with building and other construction codes, and local policies, plans, budgets, and capital improvements programs, should enable localities to cope with the impacts of OCS-related projects within their jurisdictions.

Certain guidelines in using regulations are suggested for local planners:

1. Keep all regulations and their administration as clear and simple as possible

2. Seek the assistance of other local, state, and federal agencies in:

   - preparing new and/or updating existing community regulations

   - reviewing the exploration plans, permit applications, and requests for development proposals, and

   - monitoring certain regulations wherever possible (e.g., water and air quality standards and regulations)

3. Assess local staff resources and determine their adequacy to administer and monitor new regulations

4. Require oil companies to provide in their project applications detailed data and impacts of the project on the local community to aid localities in appraising sites, environmental hazards, and other important aspects of the proposal.

Leasing

Cities and counties in North Carolina can manage industrial development and related services created by OCS oil and gas activities through the use of leases for public lands. "The use of leases by local governments throughout the U.S. is quite common, particularly for tidal and submerged lands which are restricted by law to continuous public ownership. The lease enables a landowner (public or private) to maintain a high degree of control over the use of his land. A lease provides greater control than either deed restrictions or public regulatory powers." (Dornbusch, Management of OCS-Related Industrial Development, p. II-25)

Local governments or private landowners may apply different rental fees and requirements to "service bases (generally established during the exploration phase), marine terminals, and liquified natural gas (LNG) plants. Flat rent leases are customary for service base facilities throughout the country. They are easily administered and, if appropriate rental readjustment provisions are included, they achieve a fair rate of return for the lessor. Volume-related leases entail higher costs for administration, auditing, and legal services, but stipulations could require some of these costs to be met by the lessee. The City of Seward, Alaska, has utilized this type of lease for its service base facility." (Dornbusch, Management, p. II-26) An oil and/or gas company may be unwilling to pay high rental fees for leased property before any oil and gas are discovered. A solution may require adjusting the rental fee on the lease at the end of the exploration stage to reflect minor or major discoveries of oil or gas.

"The lease provides a unique tool for a landowner to control the development which occurs both on his property and elsewhere within the community. The lessor may obtain rental fees and a variety of performance provisions limited only by the importance the lessee places upon obtaining the leased property, and the legal restrictions controlling the actions of the lessor." (Dornbusch, Management, p. II-26)

Municipalities are given the authority to lease or rent the lands they own by the North Carolina General Statute 160A-272. The city council (or other legislative body) may lease or rent any of its owned property for a period of not more than 10 years, although options to renew or extend the lease can be included.

In considering a lease for OCS-related facilities, the local government should "determine the objectives it seeks to accomplish in the agreement. Increasing revenues, decreasing costs associated with the development, and exercising the opportunities represented by industrial growth should be considered. . . . Clearly, a substantial portion of the control a municipality can maintain over industrial activity involves refusing even to consider leasing public lands when doing so would conflict with local objectives. Among its early actions a municipality should identify (preferably with the help of industry specialists) portions of its land that are appropriate sites for OCS-related industrial development." (Dornbusch, Management, p. II-28)

On the part of the oil and/or gas industry, "the concerns which will probably be foremost in the industry's lease negotiations include:

- Minimizing costs. This includes the ability to terminate the lease without delay should the exploration phase prove unfruitful or as the project is concluded. It also concerns the extremely significant factor of costs which would occur from any delay in developing support facilities for OCS operations.
- Maintaining maximum freedom from municipal control. This would suggest opposition to many provisions in the interest of the lessor.
- Ensuring continuous use of the property over the life of OCS activity." (Dornbusch, Management, p. II-28)

Summary

This chapter has described a number of options for local planners in managing impacts of OCS-related development. Primary attention has been paid to those actions which local governments can take, although the Coastal Area Management Program context is recognized along with the various federal and state OCS regulations.

To develop the local capacity to manage OCS-related projects, planners are advised to systematically prepare their communities for understanding OCS operations and regulations, communicating with key officials, evaluating community capacity to absorb OCS development, and establishing community policies and management programs. While it is possible to develop elaborate local management systems in larger metropolitan areas, even small communities should at least designate a local OCS coordinator and adopt an OCS facilities management ordinance.

The centerpiece of local regulation efforts should be the zoning ordinance. Zoning techniques judged especially useful for OCS-related projects are Special Use Permits, Waterfront Industrial Districts, Planned Industrial Districts, Industrial Performance Standards, and Site Plan Review. Additional techniques discussed include Local Environmental Impact Statements, Leasing, Policy Statements, Land Use Plans, and Permit Review Procedures.

No matter what tools are selected it will be important to keep the overall OCS management program simple, direct, and internally consistent. Whether it relies on a single zoning amendment and some informal public objectives or a number of more sophisticated options, the local effort should be seen as an inter-related system. The OCS development process is complex enough, so that all participants will appreciate a clear and straightforward local policy and implementation program whose elements work together in the public interest.

REFERENCES

American Society of Planning Officials. no date. *Anticipating and Planning for the Impacts of OCS Oil and Gas Development*. Chicago, IL: ASPO.

Baldwin, Pamela L. and Malcolm F. Baldwin. 1975. *Onshore Planning for Offshore Oil: Lessons from Scotland*. Washington, DC: The Conservation Foundation.

Brower, David J. et al. 1979. *Growth Management in Coastal Communities*. Chapel Hill, NC: Center for Urban and Regional Studies, University of North Carolina.

Clark, John, J. Zinn, and C. Terrell. 1978. *Environmental Planning for Offshore Oil and Gas. Volume 1: Recovery Technology*. Washington, DC: U.S. Fish and Wildlife Service - Biological Studies Program.

David M. Dornbusch and Company, Inc. 1976. *Management of OCS-Related Industrial Development: A Guide for Alaska Coastal Communities*. Juneau, AK: Alaska Department of Community and Regional Affairs - Division of Community Planning.

Gowen, Ann W., M.J. Goetz, and I.M. Waitsman. 1980. *Choosing Offshore Pipeline Routes*. Cincinnati, OH: EPA Office of Research and Development - Industrial Environmental Research Laboratory.

New England River Basins Commission. 1980. *Strategies for State Participation in OCS Exploration Decisions*. Boston, MA: NERBC and the U.S. Geological Survey Resource and Land Investigations Program.

__________. 1976. *Factbook*. Boston, MA: NERBC and the U.S. Geological Survey Resource and Land Investigations Program.

Office of Coastal Zone Management, U.S. Department of Commerce. January 1979. *Draft Environmental Impact Statement Prepared on Amendments to the North Carolina Coastal Management Program*. Washington, DC: Office of Coastal Zone Management - U.S. Department of Commerce.

Schneider, Devon M., ed. 1977. *Planning for Onshore Development: Discussion Papers*. Chicago, IL: American Society of Planning Officials.

Urban Pathfinders, Inc. 1975. Brown and Root Impact Study for Northampton County, Virginia. Landover Hills, MD: Urban Pathfinders, Inc.

APPENDIX A: ANNOTATED BIBLIOGRAPHY

The literature addressing the onshore impacts of Outer Continental Shelf (OCS) oil and gas development falls into two broad categories: that which presents general information about the processes and effects of offshore development and that which addresses the issue primarily through the study of areas which have already experienced or anticipated OCS development. The first group, "Overviews, Handbooks, and Methodologies," includes publications ranging from the most basic overviews of OCS facilities and activities to the most detailed methodologies. With varying degrees of detail, all of these publications work to increase the reader's knowledge and understanding of physical and institutional OCS activities, and to increase one's ability to foresee and plan for the impacts. The second category, "Case Studies," contains publications that describe how individual communities have been affected by and responded to OCS activities. These studies vary; some are descriptive, several draw explicit lessons for other communities, and others use the experience to develop methodologies for predicting effects. The third section of this bibliography, "Regional Information," includes literature that deals specifically with either North Carolina or the Mid-Atlantic region.

In the individual annotations and, to some degree, in the arrangement of citations within the two sections, the information has been presented to allow individual interpretation of each publication's usefulness.

OVERVIEWS, HANDBOOKS, AND METHODOLOGIES

This section covers a broad range of subject areas: Outer Continental Shelf (OCS) facilities, facility requirements, physical impacts, social impacts, relevant planning processes, and the institutional framework for decision making at all levels of government. The publications are arranged in stages, with those sources containing general, descriptive information cited first and the more complex, predictive material cited last. This section is divided into three subcategories: Overviews, Handbooks, and Methodologies. "Overviews" provide general information vital to understanding the facts and issues involved in OCS development and its onshore impacts. They are descriptive and explanatory, imparting both the necessary factual information about facilities and facility requirements and impacts, and a comprehensive view of the OCS issue. They differ from "handbooks" in that comparatively little emphasis is given to planning or management options. While they often include some background descriptive information, "handbooks" contain information on ways to foresee, react to, or affect OCS activities and their onshore impacts. "Methodologies" differ from the handbooks by placing a greater emphasis on the prediction of certain aspects of OCS development and impacts, and by presenting a formal framework to derive these predictions.

Overviews

These publications, as noted above, are primarily descriptive reports on either the physical processes involved in the production of offshore oil and gas or the entire socio-political process behind that production. Relatively minor attention is given to planning and management concerns. This information is very useful, especially to the planner unfamiliar with the specifics of OCS activity.

Introduction to the OCS Development Process

Gillman, Katherine (Council on Environmental Quality). 1977. Oil and Gas in Coastal Lands and Waters. Washington, D.C.: U.S. Government Printing Office. Available from GPO, Stock No. 040-000-00386-0.

This publication is a good, basic explanation of why, how, and what is going on in OCS development. It includes a short but excellent description of the stages of OCS development, a discussion of how to protect against negative effects, and an overview of agency jurisdictions. Overall, the book provides a comprehensive understanding of the facts and issues involved.

There are three particularly relevant chapters. Chapter 6, "Oil Ashore," presents several brief case studies depicting what happens during OCS development. It includes a discussion of the Gulf Coast experience, with the caveat that this is not likely to be a good example for other parts of the country, since the Gulf Coast communities were prepared and largely in favor of OCS development. A more applicable experience is that of Cook Inlet, where development occurred more suddenly. The discussion of this experience is short and simple, and describes community onshore effects. The chapter concludes with a very general discussion of likely effects on other places. The OCS process is divided into three phases: exploration, development, and production; a general explanation of onshore effects during each phase is provided.

Chapter 7, "Locations Ashore: Rigs to Refineries," is a more specific account of onshore facilities and siting requirements. It is divided into five parts: siting refineries, air and water pollution from refineries, community acceptance, pre-existing pollution, and deepwater ports. All include brief descriptions and case histories.

Chapter 10, "Protecting Communities and the Land," deals with the question of managing OCS development, and cites a helpful case study, "The Shetland Experience." It includes a discussion of Coastal Zone Management (CZM) programs and their integration with OCS decision making, states' participation in OCS leasing and regulating, and the first steps in planning for impacts.

American Society of Planning Officials and the Conservation Foundation. Anticipating and Planning for the Impacts of OCS Oil and Gas Development. An ASPO training project sponsored by the Resource and Land Investigations Program, U.S. Geological Survey, and the Office of Research and Development, U.S. Environmental Protection Agency. Available for APA or CF.

This ten-page guidebook is designed "to identify the most important information currently available to help state and local planners anticipate and plan for OCS-related development." It enumerates twelve "key points of interests," including:

1. During the period 1977-1980, the Department of Interior intends to conduct 23 lease sales permitting oil and gas exploration on the Outer Continental Shelf

2. No reliable analyses of the impacts of OCS development (beyond the exploration phase) are possible until discovery of economically recoverable oil and/or gas resources and identification of their characteristics

3. The greatest amount of offshore activity, and thus the greatest potential for onshore impacts, is during the development phase

4. Characteristics of the oil and gas fields, local social and economic conditions, legal controls, existing land use, and physical characteristics of the land and marine environments will in large measure determine the quality, design, and siting of onshore facilities. The relative importance of each can only be ascertained after oil and gas are discovered

5. Staging and support facilities tend to cluster in developed harbors, provide employment and added business, and usually have moderate environmental and fiscal effects. They may, however, conflict with existing harbor use

6. One of the most important questions in OCS development is whether to pipe or ship produced oil to shore. Commercial quantities of gas are almost always piped

7. Large scale facilities--such as platform fabrication yards and refineries--are not tied to specific sales or lease areas. When new facilities are developed, however, they are often located in rural areas on large, waterfront sites

8. Impacts are likely to be more intense in rural areas than in urban areas which are better structured to accommodate and absorb new industry with little stress

9. The scope and impact of OCS activity will vary from region to region, depending on whether the region has established OCS activity or is a "frontier region," whether onshore sites are urban or rural, the characteristics of existing economic activity, and environmental conditions

10. The greatest onshore and nearshore impacts to the natural environment from OCS facilities and activities will result from site alteration for waterfront and large scale individual facilities rather than from oil spills

11. The greatest demand for public services and, therefore, the period of greatest fiscal impact, will be during the early development stage. Fiscal impacts on rural communities will probably be adverse if development is accompanied by high rate of population growth, and

12. Regulation of development onshore related to or induced by OCS development is a "tangled web of government roles and responsibilities."

After elaborating on these points, five categories of information--time, industry activities, federal government activities, state and local activities, and onshore activities--are provided for each of the five OCS development phases (leasing, exploration, development, production, and shutdown).

The pamphlet is well done and concise, conveying a great deal of information with a minimum of verbiage.

Introduction to OCS Facilities and Facility Requirements

New England River Basins Commission. 1976. Factbook. Boston, MA: NERBC and U.S.G.S. Resource and Land Investigations (RALI). Available from NERBC.

This is the definitive encyclopedic reference on the principal onshore facilities related to offshore oil and gas development. Each chapter describes a specific facility and has three sections:

1. Description of Facility--a detailed description of the facility and activity that occurs there

2. Timing, Trends, and Options in Facility Siting--a discussion of the factors that influence and the steps involved in siting the facility in a frontier area, and

3. Characteristics, Requirements, and Impacts--a comprehensive description of land, waterfront, water, energy, transportation, labor and capital requirements; site alteration and construction impacts; and environmental impacts (air, wastewater, sedimentation and runoff, solid waste, noise, and aesthetics).

Contents:

Chapter 1 - temporary service bases (supporting exploration); permanent service bases; bases supporting platform and pipeline installation

Chapter 2 - repair and maintenance yards

Chapter 3 - determining a shelf-to-shore transportation strategy; pipelines and landfalls; marine tanker terminals

Chapter 4 - partial processing facilities

Chapter 5 - gas processing and treatment plants

Chapter 6 - refineries

Chapter 7 - petrochemical plants

Chapter 8 - platform fabrication yards

Chapter 9 - pipe coating yards

Chapter 10 - ancillary industries (drilling equipment, trucking, helicopters, diving, labor contracting, oil spill recovery, machine shops, and others)

Chapter 11 - district offices

Chapter 12 - land pipeline systems

Appendix A - impacts of the major pollutants generated by onshore facilities (air emissions, noise, water discharges, and solid waste)

Appendix B - impacts of site alteration and construction (land site development and development on wetlands and coastlines)

Appendix C - vehicular air and noise emissions

Clark, John, J. Zinn, and C. Terrell. 1978. *Environmental Planning for Offshore Oil and Gas. Volume 1: Recovery Technology*. Washington, D.C.: Conservation Foundation, U.S. Fish and Wildlife Service, Biological Services Program. Available form USFWS, National Coastal Ecosystems Team.

(Volume 1 of a five-volume series of reports written by the Conservation Foundation for the U.S. Fish and Wildlife Service.)

This volume is "mainly concerned with the physical description of offshore oil and gas development activities as (1) a direct cause of impacts offshore and (2) a generator of indirect impacts inshore and onshore." It is divided into two major parts: "Resource and Recovery," and "OCS Development System--Introduction and Guide." Part I is primarily general background information. It deals with very broad OCS and energy development issues such as U.S. energy demands and production trends and offshore development potentials and resource estimates. It also introduces the Conservation Foundation's classification of the six major phases involved in the development process: pre-exploration, geological and geophysical exploration, exploratory drilling, field development, production, and shutdown of facilities.

Part II contains a brief discussion of several aspects of general OCS development: community acceptance, environmental constraints, regulatory aspects, and industry decision factors. Its main focus, however, is on fifteen "OCS projects" which are grouped into three major categories: offshore development projects, onshore development projects, and processing projects.

This volume contains the primary information necessary to acquaint the reader with the OCS industry and some of its issues. But its approach is rather dry and uninteresting. A large foldout illustration of all OCS facilities is provided. This is helpful since illustrations are not found in many of the other publications.

Alaska Consultants, Inc. 1976. Marine Service Bases for Offshore Oil Development. Juneau, AK: Alaska Department of Community and Regional Affairs, Division of Community Planning. Available from NTIS, No. PB 262-892.

This is a well done, factual account of the facilities involved in the OCS process and includes many related aspects affecting these facilities and their land and labor requirements. There are four major sections of the book. The first is a general introduction to offshore oil operations, the service bases necessary to support these operations, and the requirements for locating service bases. The second section deals specifically with materials and service requirements, the third with service base facilities, and the fourth with land and labor requirements.

The publication is very informative, containing much detailed information about all onshore related facilities and their requirements.

Handbooks

These are publications which, in addition to providing some background information, present planning and management options for dealing with OCS activities: when, where, and how to address different issues. This large number of publications offers different (yet often overlapping) perspectives on varied aspects of management options surrounding OCS activities. Some of the publications are general; they attempt to deal with all or most aspects. Others focus more on one particular aspect. Some deal specifically with environmental or socio-economic impacts while others describe the institutional framework and actual planning mechanisms for addressing these impacts. The lines between them are hazy; the individual annotations define the emphasis and scope of each publication better than the general headings under which each is placed.

General

Laroe, Edward et al. 1975. Coastal Management Aspects of OCS Oil and Gas Developments. Washington, D.C.: U.S. Office of Coastal Zone Management. Available from NTIS, No. PB 249-751.

This book provides a good brief overview of OCS petroleum and gas activities and a general description of federal agencies' roles and responsibilities in OCS development, offshore and onshore activities and facilities, socio-economic and environmental impacts resulting from OCS activities, and suggestions for state planning and management (administrative organization, information collection, and modes of implementation).

It contains an annotated bibliography and a directory of federal agencies and other organizations concerned with OCS development.

Grella, Michael. 1970. Technical Assistance Manual: Planning for the Onshore Impacts of Offshore Oil and Gas Development (working draft). Fort Lauderdale, FL: Florida Atlantic University - Florida International University Joint Center for Environmental and Urban Problems. Available from FAU-FIU Joint Center.

This manual describes OCS development stages and onshore facilities, including environmental (air quality, water quality, and water supply) impacts of several onshore facilities as well as general socio-economic and fiscal impacts. It contains a discussion of alternative management strategies available to local governments including environmental impact assessments, various zoning tools, and industrial performance standards.

Coastal Environments, Inc. 1978. Siting Energy Related Facilities in Louisiana's Coastal Zone. Baton Rouge, LA: Louisiana Department of Transportation and Development. Available from LaDOTD, Coastal Resources Program.

This briefly describes several energy facilities that typically locate in coastal areas (including refineries, gas processing plants, LNG terminals, pipelines, offshore ports, platform yards, OCS support service bases, pipe coating yards, and tank farms) and their site requirements, products, and wastes. It discusses the environment of coastal Louisiana and the institutional aspects of energy facility siting (including the concerns and responsibilities of federal, state, and local agencies). It outlines a siting procedure with three stages (alternative identification, project selection, and facility implementation) to expedite facility construction while protecting culture and environment.

Environmental

Clark, J. and C. Terrell. 1978. Environmental Planning for Offshore Oil and Gas. Volume III: Effects of Living Resources and Habitats. Washington, D.C.: Conservation Foundation, U.S. Fish and Wildlife

Service, Biological Services Program. FWS/OBS - 77/14. Available from USFWS, National Coastal Ecosystems Team.

(Volume III of a five-volume series of reports written by the Conservation Foundation for the U.S. Fish and Wildlife Service.)

This volume is the primary working document of the series. It is a condensed reference source identifying ecological disturbances likely to occur from OCS development onshore. It is structured to serve as a guide to environmental impact assessment for Fish and Wildlife Service biologists, but its usefulness is not limited to this purpose. Like Volume II, it divides OCS development into "projects" and "subprojects," and identifies site requirements, site disturbances, and other environmental impacts and effects. Like the others in this series, this volume is quite comprehensive but rather dry and difficult to read.

Shanks, Larry. 1978. Coastal Systems and Management Options Related to Outer Continental Shelf Development. Washington, D.C.: U.S. Fish and Wildlife Service. Available from NTIS, No. PB 297-635.

This book briefly describes key coastal habitats: coastal wetlands, shellfish beds, grass beds, tributary streams, endangered species habitats, spawning and nursery areas, and bird rookeries. The purpose and process of five activities associated with OCS development are detailed (dredging, pipeline construction, site preparation, and the environmental problems each presents). Alternative management options, including planning procedures and construction techniques are outlined for each activity to minimize the impact of development on living resources. It is a brief and handy guidebook for planners.

Longly, W.L., R. Jackson, and B. Snyder. 1978. Managing Oil and Gas Activities in Coastal Environments. U.S. Fish and Wildlife Service, Biological Services Program. FWS/OBS - 78/54. Available from USFWS, National Coastal Ecosystems Team.

This short, well done, and informative publication primarily addresses the environmental and biological impacts of OCS development.

The first section describes three ecosystems--uplands, seasonally flooded wetlands, and saturated wetlands and open water. The second deals with petroleum development impacts on these three systems. Phases of petroleum development--pre-exploration, site access and preparation, drilling, production, pipeline installation, spills and cleanup, and termination--are listed and often illustrated. Each phase is then divided into three areas for further illustration: activity, impact, and comments.

Gowen, Ann, M.J. Goetz, and I.M. Waitsman. (New England River Basins Commission). 1980. Choosing Offshore Pipeline Routes. Cincinnati, OH: EPA Office of Research and Development, Industrial Environmental Research Laboratory. Available from NTIS, No. EPA-600/7-80-114.

This book is an excellent description of the major problems associated with offshore pipeline installation and pipeline landfalls and the engineering and routing solutions for each.

It presents technical criteria for the selection of pipeline routes based on the feasibility of installation and the geological and ecological characteristics of the route. This analysis includes general criteria used by industry in selecting routes, areas to avoid in pipeline siting, and mitigation methods to minimize unavoidable impacts. Various offshore pipeline and landfall installation methods and inspection procedures are discussed.

Four key issues regarding offshore oil and gas pipelines are identified:

1. Pipeline failures which result in leaks and spills--from corrosion, anchor dragging, bottom trawling, and, most importantly, unstable bottom conditions

2. Damage to sensitive environmental areas along the route--from habitat displacement, turbidity, and physical and chemical changes in the water column

3. Loss of access to fishing grounds--from pipelines acting as obstructions to bottom fishing, and

4. Damage or loss of fishing gear--from snagging on exposed pipelines and on bottom debris resulting from pipeline trenching.

New England River Basins Commission. 1980. Pipeline Landfalls: A Handbook of Impact Management Techniques (draft). Boston, MA: NERBC 0 RALI. Available from NERBC.

This publication presents methods for minimizing the environmental impacts of pipeline installation at the landfall by (1) using construction and restoration techniques appropriate to the physical constraints of a particular site ("technical methods"), and by (2) cooperative planning between government and industry to choose landfall sites and develop acceptable and effective regulations and monitoring programs for particular installations ("planning methods").

Zinn, J. Environmental Planning for Offshore Oil and Gas. Volume II. Effects on Coastal Communities. Washington, D.C.: Conservation Foundation, U.S. Fish and Wildlife Service, Biological Services Program. FWS/OBS-77/13. Available from USFWS, National Coastal Ecosystems Team.

(Volume II of a five-volume series of reports written by the Conservation Foundation for the U.S. Fish and Wildlife Service.)

This volume describes a method to predict the secondary growth effects of primary OCS development and the ecological impacts that may accompany these effects. The volume is not designed to provide the planner with the ability to make forecasts, but to provide a basic understanding of the data needs and sequence of forecasting populations and community impacts for persons unfamiliar with the subject. It is written in simple, basic language. Four sections present the simplified forecasting format:

1. Introduction
2. Forecasting employment and population--briefly describes some commonly used procedures and a sample forecast is outlined
3. Community facilities--discusses housing, public utilities and services, transportation, schools, recreation, and commercial facilities. The section identifies accepted planning standards and displays examples from other study areas, especially the Northampton County, Virginia study on impacts of a proposed platform fabrication yard
4. Potentials for ecological disturbance--lists 20 "sub-projects" which will result from OCS projects and briefly discusses their impacts.

Treatment of community effects is somewhat superficial; these effects are discussed only as a means to reach impacts on living resources and habitats, which is the main thrust of the entire study. (See Volume III, Effects on Living Resources and Habitats.)

Energy Research and Development Administration - Office of Planning, Analysis, and Evaluation. 1977. Managing the Socio-economic Impacts of Energy Development: A Guide for the Small Community. Washington, D.C.: U.S. Government Printing Office. Available from USGPO, Stock Number 061-000-0005-4.

This handbook designed to help local government plan for the expansion of public services to meet the needs of energy facility development. It outlines questions facing the local planner regarding:

economic and demographic impacts, housing, transportation, water supply, solid waste, wastewater treatment, recreation, education, health care, and community safety. The development of capital investment programs and alternatives for raising public revenues are detailed. The volume does not prescribe a particular planning process; rather, it introduces the issues and alternatives for action which may be relevant to local planners.

Institutional

U.S. Geological Survey and Council on Environmental Quality, Outer Continental Shelf Oil and Gas Information Program. 1979. Directory to Federal, State, and Local OCS-Related Activities and Contacts. Reston, VA: USGS. Available from USGS, OCS Oil and Gas Information Program, Open File Report 79-1981.

This handbook is a good, complete source of information on federal roles in OCS development which also includes a summary of North Carolina state roles. It is divided into four sections and two appendices with a general introduction in Section One. The second, a discussion of major federal administrative and monitoring activities of the OCS resource management process, is described in four phases: leasing, exploration, development, and production. Within these four phases, 19 major pre- and post-lease steps are identified. Federal agencies involved in each step and the roles they play are identified. The chapter also includes a lengthy table listing the responsible federal office/agency, participating office/agency, and type of participation for each of the 19 base steps.

The third chapter reviews the major state government programs pertaining to the OCS process, both those responding to federal initiatives and those autonomous actions initiated by the states themselves. It is primarily a table listing and a short description of existing programs; it does not discuss ways in which states can influence OCS decision making. A state agency listing, arranged alphabetically, is also included. The fourth chapter describes local participation at the county and municipality level and identifies the mechanisms that can be used by sub-state jurisdictions to affect the OCS process.

Banta, John. 1978. Environmental Planning for Offshore Oil and Gas. Volume IV: Regulatory Framework for Protecting Living Resources. Washington, D.C.: Conservation Foundation, U.S. Fish and Wildlife Service, Biological Studies Program, FWS/OBS-77/15. Available from USFWS, National Coastal Ecosystems Team.

(Volume IV of a five-volume series of reports written by the Conservation Foundation for the U.S. Fish and Wildlife Service.)

This is a reference document which summarizes federal regulatory programs affecting OCS (offshore and onshore) oil and gas leases. It is designed to explain how the Fish and Wildlife Service relates to OCS rules and procedures, but is not a comprehensive guide to OCS development regulations. It is divided into three sections: the first deals with the Fish and Wildlife Service itself, the second deals with the OCS process, and the third considers federal, state, and local roles in nearshore/onshore OCS development permitting and access to decisions through the NEPA process.

New England River Basins Commission. 1980. Strategies for State Participation in OCS Exploration Decisions. Boston, MA: NERBC-RALI. Available from NERBC.

This publication describes the various documents that states will review in the OCS exploration planning process including Corps of Engineer permits, environmental assessments, and NPDES reports. It discusses various review and planning needs, institutional arrangements (e.g., intergovernmental coordination), and available funding sources to help state-level planners ensure effective responses to exploration proposals. It outlines how several states have structured their participation in the exploration planning process, and is a more useful report for state planners than for local planners.

New England River Basins Commission. 1980. State Participation in OCS Development and Production Decisions (draft). Boston, MA: NERBC-RALI. Available from NERBC.

The various types of participation open to states in the development and production stage are detailed including the review of plans and permit applications, consistency certification, and such ongoing programs as the OCS Oil and Gas Information Program. Each document or program is discussed in terms of its function in the overall process, related federal actions and responsibilities, and opportunities for state input. The procedures that three states have developed to coordinate their participation in development and production decisions are cited.

Williams, David C. 1977. State Information Needs Related to Onshore and Nearshore Effects of OCS Petroleum Development. Washington, D.C.: U.S. Office of Coastal Zone Management and the Bureau of Land Management. Available from NTIS, No. PB-266-001.

This volume discusses the context of coastal states' OCS-related management decisions and the information required to make them. It identifies the following concerns common to nearly all coastal states:

1. protecting coastal natural resources
2. protecting existing economic activities
3. improving state access to federal and industry information about development plans and resource reserve estimates, and
4. improving the Department of the Interior's OCS leasing and management process.

The concerns of different regions of the country are cited. These may vary depending on the region's experience with hydrocarbon development, its economic and environmental conditions, and public attitudes. The following key information needs for state and local decision makers are identified:

1. potential environmental, economic, fiscal, and social impacts of offshore development
2. characteristics and requirements of OCS activities and related onshore facilities
3. environmental baseline data, and
4. available mitigation techniques.

The available information most used by states in studying OCS development and formulating strategies for managing OCS-related activity are detailed, as well as the extent of local government involvement in OCS decision making. Localities that have been prepared or are preparing their own OCS studies and plans are cited (pp. 24-28), and two examples of local ordinances governing OCS-related facilities are provided.

Planning

David M. Dornbusch and Company, Inc. 1976. Management of OCS-Related Industrial Development: A Guide for Alaska Coastal Communities. Juneau, AK: Alaska Department of Community and Regional Affairs, Division of Community Planning. Available from David M. Dornbusch and Company, Inc.

This is an excellent publication, one of the best written and arranged handbooks that local governments can find. Although it focuses on issues and problems common to Alaska communities, most are applicable to other communities outside of Alaska. The book's introduction states: "Recognizing that small communities have limited resources and staff to perform analysis, planning, and management activities, the report focuses on management techniques which are easiest to administer." Its objective is to offer a "range of alternative management procedures and tools which can be used to achieve diverse community needs and objectives related to OCS activity." Seven fundamental actions necessary for communities to manage OCS-related developments are listed. The first of the report's three sections is a detailed description of seven "essential tasks." The second, entitled "Management Tools," is a discussion of the three types of tools available to manage on-shore developments: leases, public powers, and impact methods. According to the authors, this section should "be used first to gain a basic understanding of these tools, and then to select a general management approach." The last section, "Application of Management Tools to Special Objectives," suggests ways to use the management tools to achieve particular financial, economic, social, and environmental objectives.

Schneider, Devon M., ed. 1977. Planning for Onshore Development: Discussion Papers. Prepared for an ASPO Training Project, "Onshore Impacts of OCS Oil and Gas Development." Chicago, IL: American Society of Planning Officials. Available from APA.

This volume was prepared as background material for an ASPO workshop session entitled "Local Planning Approaches for Industrial Facility Siting." The papers focus broadly on planning for new industry and not just oil and gas facilities. They are divided into four major areas, each of which includes extensive "supporting materials which illustrate local government responses to the issues." These include:

1. policy development

2. local industrial development programs
   - determining a community's suitability for new industrial development
   - packaging a community to attract industry
   - using inducements to attract industry

3. impact assessment
   - environmental impacts
   - socioeconomic
   - fiscal impacts

4. land use and development controls
   - local requirements for environmental impact statements (EIS)
   - zoning for new coastal industries
   - identifying appropriate environmental performance controls
   - developing industrial performance standards
   - zoning to prevent sprawl

This is a potentially valuable volume. Much of the "supporting material" is excerpted from various sources, but is well chosen and provides good examples of how localities have dealt with their problems. The material is not well arranged and, therefore, not particularly inviting or easy to read. However, the material is very relevant and useful.

Methodologies

This section includes formal methods or models for deriving resource and impact estimates necessary for the OCS decision-making process. The two most comprehensive and best-known methodologies, those of the New England River Basins Commission and Roy Weston, are designed primarily for use early in the process. As such, they are probably of limited use to the local planner who will most likely enter the decision-making process after such information is derived by the methodologies. Included in this category is a "User's Guide" to these assessment methods. Two additional models are concerned with estimates needed in later stages of the decision-making process, but they may also be of limited use to local planners due to their high degree of complexity and theoretical nature.

New England River Basins Commission. 1978. Methodologies for OCS-Related Facilities Planning. Boston, MA: NERBC-RALI. Available from NERBC.

Three methodologies are presented in this publication:

1. the determination of rough pre-exploration figures on potentially recoverable reserves and the timing and scale of offshore activity
2. the development of rough estimates of the type and number of onshore facilities required for a given level of offshore activity in the leasing region, and
3. the identification of potential sites for these facilities.

The first and second methodologies are more useful for state planners than for local planners since they concern estimates and decisions made before the lease sale. The last methodology is helpful for local planners who want to identify opportunities and constraints for onshore development. It stresses the consideration of an industry's site selection criteria and the identification of public policy criteria for site location.

The methodologies are not intended as a "cookbook" or predictive tool due to the inherent uncertainties in OCS development regarding offshore reserves. They do represent several logical and flexible thought processes for the planner to follow to develop an understanding of OCS facility siting.

Roy F. Weston, Inc. 1978. Methodology for Assessing Onshore Impacts for O.C.S. Oil and Gas Development. West Chester, PA: Roy F. Weston, Inc. Available from Weston.

The Weston Methodology, thought by some to provide the most comprehensive and thorough forecasts of offshore activities and onshore facilities and impacts, is a computer-based method aimed primarily at state and multi-county regional planners. Local planners are not considered likely users since the methodology objective is to offer guidelines for obtaining early projections of future activities. These guidelines will often be superfluous to the local planner who can obtain the actual facts and figures which the Weston methodologies only estimate.

The study is in three volumes: I - Executive Summary, II - Methodology, and III - Baltimore Canyon Test Case. The executive summary contains the assumptions, elements, and assessment processes of the methodology and a discussion of issues, limitations, time, and skills required. This volume is to be used to decide whether or not to use the Weston Methodology. Volume II, the main volume, is divided into six chapters. The first, "Industrial Requirements," presents the quantitative base for the entire study. In turn, it is divided into twelve sections, the first of which defines time-phased drilling activities, development production scenarios, platform installations, oil and gas production, and well workover schedules. At this point the planner or analyst plugs in the only information necessary for the entire methodology: USGS estimates of reserves, the number of tracts offered for sale (from the Bureau of Land Management), tracts sold, size of find, or, when available, more current base information; and chooses between three alternative transportation schemes presented. The chapter's remaining eleven sections use the information generated in section one to estimate onshore activity demands including materials, jobs and salaries for all phases, transportation requirements for boats and helicopters, onshore facility requirements (land, electric power, water, capital costs, and environmental factors), liquid wastes, sanitary and solid wastes, tanker terminal wastes, and ballast wastes. Information provided by chapter one is also used subsequently to identify and rank probable locations for primary and secondary onshore facilities, and the environmental constraints associated with these locations, and to evaluate economic, demographic, environmental, and fiscal impacts. In Volume III, the "Baltimore Canyon Test Case," the methods of Volume II are applied and fully described.

Williams, D.C. and K.B. Hom. 1979. Onshore Impacts of Offshore Oil: A User's Guide to Assessment Methods. Washington, D.C.: U.S. Government Printing Office. Available from USGPO, Stock No. 024-000-00859-2.

According to the authors, this is a guide to the "three principle methodologies for assessing and planning for the onshore impacts of offshore oil." NERBC's Onshore Facilities Related to Offshore Oil and Gas Development, Weston's Methodology for Assessing Onshore Impacts of Offshore O.C.S. Oil and Gas Development, and the Conservation Foundation's Environmental Planning for Offshore Oil and Gas are included in this bibliography. But only two are included in this section since the Conservation Foundation's study is not considered a formal methodology.

Since the usefulness or applicability of these methodologies to the local planner is limited, usefulness of a guide to these methodologies is also limited. However, if more information on these assessment methods is desired, this guidebook provides an excellent means of understanding and comparing the methods. It includes a chapter on criteria for selecting methods and individual chapters on each of the three methodologies, which include a summary of contents, the purpose, scope, and expected results, examples of use, and the time and skill requirements needed for each. Also included are a brief annotated bibliography and a chapter about the OCS process, leasing scheme, and the authorities of agencies at each level of government.

The guide is clearly written and useful both as a guide to the three documents and as an explanation of basic OCS facts and issues.

Peat, Marwick, Mitchell, and Company. 1979. Developing Predictive Indicators of Community and Population Change. Technical Report No. 26, Alaska Socioeconomic Studies Program. Anchorage, AK: Bureau of Land Management, Alaska OCS Office. Available for NTIS, No. PB 80-11628.

The goal of this study is to "improve our ability to anticipate social and economic effects on energy development in Alaska communities." The primary problem the authors address is that the "same general type of development is likely to result in different changes among individuals and communities." The report presents results of research that attempt to explain these differences, and the authors draw upon the oil pipeline experience of Fairbanks and Valdez to identify relationships between community and individual characteristics that can be observed prior to and after impact. They state that in the future, relationships uncovered by their research may be shown to apply to communities and individuals in general (or at least to a large proportion of the population). The report includes a set of questionnaires to "measure key community and individual characteristics in baseline studies," and methods by which the observed characteristics can predict community and individual responses to new development.

Huskey, Serow, and Volin. 1979. Design of a Population Distribution Model, Technical Report No. 24, Alaska Socioeconomic Studies Program. Anchorage, AK: Bureau of Land Management, Alaska OCS Office. Available from NTIS, No. PB 299-658.

> This report is part of the Alaska Socioeconomic Studies Program which is described in more detail in Part II of this bibliography. Though the program is an extensive case study of Alaska, many of the individual studies comprising the program can stand alone. Both this report and the one immediately succeeding it are attempts to develop predictive models or indicators of selected impacts of OCS development. A population impact model is developed to assess the impact of OCS petroleum development on small Alaska communities, and includes an extensive "Review of Existing Models" (such as OBERS and several econometric models). The authors then move from this review to their design of a population model for small Alaska communities which is "community oriented, and designed to accommodate the lack of data and need for flexibility at the local level." It describes population growth in three phases: baseline, development, and operation of OCS activities. In Part 3 of the report, the model is applied to the oil boom in Kenai (1960-1975) to test and analyze its usefulness.
>
> Although this exact study model may not be easily applied to places other than Alaska, the book's review of existing models is helpful to planners.

CASE STUDIES

This section contains case studies of the onshore impacts of OCS development and the strategies employed by state and local governments to handle them. In examining these case studies, a search was made for potential impacts or decision-making guides which would be relevant for North Carolina as a "frontier area" with little experience in OCS oil and gas activity. None of these specific actions is offered for North Carolina planners to follow. Instead, by examining how OCS development has been received and planned for in a variety of community contexts, from Louisiana to Alaska to Scotland, planners in coastal North Carolina can gain a deeper understanding of specific impacts and ways to tailor planning to the particular needs, concerns, and resources of different communities. The chapter contains three sections: general case studies, impact assessments, and impact projections and management strategies.

General Case Studies

These studies provide general overviews of the history and management of OCS development in various regions. They are insightful introductions to the problems faced by planners in "frontier" areas.

Baldwin, Pamela L. and Malcolm F. Baldwin. 1975. Onshore Planning for Offshore Oil: Lessons from Scotland. Washington, D.C.: Conservation Foundation. Available from CF.

> This book describes OCS development that has occurred in Scotland and the environmental and social impacts of onshore facilities. Scotland is a "frontier" area unfamiliar with oil and gas development which is experiencing a rapid buildup of OCS activities. It provides valuable lessons for frontier area development in the U.S.
>
> The authors discuss the Scottish experience with the various stages of OCS development and the physical, economic, and institutional factors affecting related onshore development. They provide case studies on the planning, construction, and impacts of pipeline landfalls, platform construction yards, deepwater tanker terminals and tank storage farms, refineries, and harbor bases. The case studies draw on experience in a variety of geographic and socio-economic environments, from the large, but relatively depressed, port city of Aberdeen to the small, remote villages of the Shetland Islands.
>
> The Baldwins also discuss the political and institutional planning framework in Scotland and its effect on OCS development--especially on the structure of public participation and the subordinance of local and regional concerns by national energy concerns. The study concludes with a summary of findings about the Scottish OCS experience and a series of recommendations for planning in the United States. These include :
>
> 1. early, active (vs. reactive) planning by coastal states and localities
> 2. the preparation of regional impact statements at the federal level, in cooperation with state and local governments, before specific tracts are proposed for leasing
> 3. the supplementation of federal impact statements by state and local impact statements on each onshore development proposal, and
> 4. federal funding for state and local planning for onshore impacts.
>
> This book is an excellent preliminary reading that discusses a full range of impacts and planning environments.

Sevy, John F. (Peat, Marwick, Mitchell and Company). 1979. Socioeconomic Impact of Selected Foreign OCS Developments. Anchorage, AK: Bureau of Land Management, Alaska OCS Office. (Alaska OCS Socioeconomic Studies Program). Available from NTIS, No. PB 297-114.

This publication describes foreign experiences, primarily related to the potential OCS impacts in Alaska with relevance for planning in all frontier areas including North Carolina.

Part I - North Sea (Scottish) Experience

Chapter 1 - Economic and Social Issues: Presents the role of oil and gas activity in the Scottish economy and its impact on regional economic development (including employment creation, sectoral shifts in employment, and difficulties in forecasting economic activity and employment) and on Scottish culture (including migration patterns, social problems, and duration of impacts). This section would be of special interest to regional economic development planners.

Chapter 2 - Administrative and Political Issues: Is of particular interest to local planners and administrators. It discusses the impacts of development on local governments, politics, and planning systems, especially in local fiscal planning and the provision of housing and other services. It presents case studies on the use of "planning inquiries" to assess public reaction to oil-related development and cites variations in local planning approaches. Chapter 2 describes the consequences of the absence of clear, established means of local control over development decisions.

Chapter 3 - Oil and Fishing: Discusses employment shifts in the fisheries industry due to oil industry demands, questions of access and debris affecting fishing operations, and competition between the two industries for harbor space and facilities.

Chapters 2 and 3 address concerns identical to those that will face local planners in North Carolina and provide an informative review of issues.

Part II - Canadian Beaufort Experience: A much shorter and less detailed account than the Scottish experience in Part I. It deals primarily with the socio-economic impacts of OCS development on small villages in the Canadian Arctic and is not as relevant to North Carolina.

National Association of Counties. 1976. Serving the Offshore Oil Industry: Planning for Onshore Growth, Northampton County, Virginia. Case Studies on Energy Impacts, No. 5. Washington, D.C.: National Association of Counties. Available from NACo.

This publication is a case study of Northampton County's experiences with Brown and Root's plans to build a fabrication yard. The text is mainly a history of events transpiring during Brown and Root's negotiations with the county to get a piece of land rezoned from agricultural to industrial to build a fabrication yard. It details significant events and ways that other communities can benefit from the county's experiences in their planning efforts.

The report is divided into twelve sections; the first three constitute a critical history and the remainder are divided by specific issues (i.e. education and highways). Each gives a description of actions taken and ways that other local governments should approach these issues.

The study concludes that "local governments should realize that industry must--and is able to--contribute to the solutions, but industry may need to be educated on its role. The conditions agreed to by Brown and Root came only as a result of very insistent questions by county leaders and citizenry," (p.35). The study ends with 16 straightforward and helpful "Guidelines." The report is excellent and very useful to local planners. It gives them an idea of what to expect from OCS development that is far more tangible than the expectations generated by numbers, timelines, and methodologies.

Impact Assessments

These reports primarily assess onshore environmental and socioeconomic impacts that have already occurred in OCS development areas. Most of the reports also discuss management reponses to those onshore impacts.

Mumphrey, Anthony et al. 1977. OCS Development in Coastal Louisiana: A Socio-economic Impact Assessment. Baton Rouge, LA: Louisiana Department of Transportation and Development (New Orleans University Urban Studies Institute Report to the Louisiana State Planning Office). Available from NTIS, No. PB 283-409.

This publication quantifies broad socioeconomic impacts in terms of production, jobs, population, and public service costs, and discusses local planning and fiscal capabilities to deal with OCS-related development.

Chapter 2 - Estimating OCS Related Coastal Zone Employment and Population: Uses an input-output model and other techniques to estimate levels of production, employment, and population attributable to OCS development in each coastal parish (county).

Chapter 3 - Public Section Expenditures in the Coastal Zone: Uses the results of Chapter 2 as the basis for computing estimated state and local public service costs (for education, highways, police and fire protection, water supply, sewerage, solid waste disposal, health, and recreation) attributable to the OCS-related populations.

Chapter 4 analyzes local fiscal needs and expenditures and the impact of OCS-related development on local fiscal capabilities. It also presents formulae for allocating among the parishes potential CEIP grants and credit assistance.

Chapter 5 discusses the stages and capital and maintenance costs of development in wetlands.

Chapter 6 assesses the effectiveness of the planning and management capability of local governments and recommends improvements.

Chapter 7 - Guidelines for Creating a Citizen Involvement Program: Discusses the role and structure of citizen participation and how it can be tailored to the individual parishes.

Mathematical Science Northwest, Inc. and Human Resources Planning Institutes, Inc. 1976. A Social and Economic Impact Study of Offshore Petroleum and Natural Gas Development in Alaska: Phase I. Anchorage, AK: Bureau of Land Management, Alaska OCS Office. Available from NTIS, No. PB 264-705.

This publication studies the economic and social structure of Alaska's Kenai region (Cook Inlet) and the change attributable to OCS development. This analysis is used to develop economic impact models with predictive accuracy for small frontier areas in other parts of Alaska and to gain insights into the nature of social changes facing them.

Part I is a detailed economic analysis which describes the impact of hydrocarbon development on the region's economy from 1960 to 1975 and derives economic base and input-output models to estimate historical levels of employment attributable to OCS development in the region.

Part II is an analysis of social and infrastructural impacts which discusses the impacts of OCS-related activities on social service delivery, demographic trends, changes in the housing stock and public utility systems, and land use changes.

Impact Projections and Management Strategies

These case studies relate the experiences of areas with no prior history of OCS development. This group of reports includes: (1) publications which primarily use estimates of offshore hydrocarbon resources to project onshore facility needs and their impacts, (2) publications which analyze roles and strategies for state and local decision makers, and (3) publications which present criteria and procedures used in siting OCS-related facilities.

Onshore Facility Needs and Impacts

Urban Pathfinders, Inc. 1975. Brown and Root Impact Study for Northampton County, Virginia. Landover Hills, MD: Urban Pathfinders, Inc. Available from Urban Pathfinders.

> This impact study for the Brown and Root platform fabrication yard to be constructed in Northampton County, Virginia, was done by an impartial firm at the request of the county and provides a good example of the questions that should be addressed. It contains six substantive chapters: economics, population, housing, public services and transportation, natural features and land use, and public finance. Each chapter is comprised of two main parts: Northampton County's current situation and trends, and Brown and Root's needs. This method of presentation works well and points out areas of conflict clearly and effectively.
>
> The last chapter contains conclusions and Urban Pathfinders' recommendation that the county implement the proposal, but only under certain conditions. Included is a schedule of actions which should be taken to implement the recommendations.
>
> The study, though quite specific to the area involved, serves as a good example of the issues which should be addressed when a conflict about OCS development arises.

New York State Outer Continental Shelf Study Program. 1977. New York State and Outer Continental Shelf Development: An Assessment of Impacts. Albany, NY: New York State Department of Environmental Conservation. Available from N.Y. State Department of Environmental Conservation.

> This publication provides a fairly thorough and comprehensive explanation of the OCS issues facing New York. The phases of OCS leasing and oil and gas exploration and development are described, as well as the impacts resulting from three scenarios (high finds to low finds) on the economy of the state and the coastal environment. A description of the natural and man-made environments of the New York Metropolitan Region and Long Island (including selected energy and maritime industries, natural features and environmental quality, and recreation and commercial fishing) is also detailed.
>
> The book emphasizes the potential conflicts OCS activity may have with other marine and marine-related activities (i.e., tourism and fisheries) as well as the potential economic benefits, and views the energy needs of the state and the potential energy supply from

OCS development. The findings of three previous OCS facility site suitability studies (by the Port Authority of New York and New Jersey, the New York City Planning Commission, and the Nassau-Suffolk Regional Planning Board) are also reported.

The volume discusses federal and state legal and regulatory responsibilities in such areas as leasing, exploration procedures, development procedures, oil spills, facility siting, air quality, and water quality, but presents no methodologies for planning or scenario development.

New York State Outer Continental Shelf Study Program. 1977. Attracting OCS-Related Onshore Facilities and Activities: An Assessment of Prospects for New York State and their Economic Benefits. Albany, NY: New York State Department of Environmental Conservation. Available from NTIS, No. PB 285-197.

A good general discussion of locational factors affecting the types of onshore activity most likely to locate in New York are provided in this volume. It uses a range of three "find" scenarios (a high oil and gas find, a very high gas find, and a low oil and gas find) to derive rough estimates of peak-year employment, income, and revenue from income and sales taxes attributable to OCS development. It briefly describes how three agencies identified potential sites for onshore development in the Port of New York and on Long Island.

Kalter, Robert and Wallace Tyner. 1975. Atlantic Outer Continental Shelf Energy Resources: Economic Implications for Long Island. Ithaca, NY: Department of Agricultural Economics, Cornell University. Available from NTIS, No. PB 246-963.

This publication describes the geological setting of the Baltimore Canyon and Georges Bank lease areas and derives a range of potential reserves which could have an impact on the Long Island economy. It roughly estimates the level and timing of private sector production costs and direct employment requirements associated with the various stages of offshore development, and discusses the application of three methods (economic base analysis, regional input-output analysis, and econometric modeling) to estimate indirect economic impacts of oil spills, refinery impacts, and siting considerations and ways of dealing with the net fiscal burden usually faced by local governments when OCS-related development occurs.

Much of the report concentrates on the uncertainty of estimating hydrocarbon reserves and their related economic impacts, and deals primarily with regional economic, not environmental, impacts.

New England River Basins Commission. 1976. Estimates for New England. Boston, MA: NERBC-RALI. Available from NERBC.

This volume provides a detailed look at the onshore facilities and impacts which might be expected in New England from three levels of oil and gas discovery on Georges Bank: a high oil and gas find, a medium find, and exploration activity but no commercial find. Included are sections on scenario development and estimating the levels of offshore activity (drilling rigs, platforms, and pipelines) necessary to produce each level of discovery. It applies information about onshore facilities presented in NERBC's Factbook to estimate the number of onshore facilities associated with the three levels of onshore development.

Research and Planning Consultants, Inc. 1977. Offshore Oil: Its Impact on Texas Communities. Austin, TX: Texas Coastal Management Program. Available from Texas Coastal Management Program.

The purpose of this study is to "develop a methodology which isolates potentially significant issues for affected jurisdictions and to analyze these issues in terms of their timing and magnitude." The technique used to accomplish this objective is the development and analysis of three OCS development scenarios, "chosen to represent a broad range of locations, time frames for activities, employment and equipment requirements, and other factors." Each scenario describes offshore events and the resultant activities, requirements, effects, and impacts are then traced to the onshore sites most likely to be involved.

The report is in four volumes: I, Executive Summary; II, Local Impact Scenarios; III, Aggregate State Impacts; and IV, Appendices. The information and analysis that comprise the first three volumes are applicable only to Texas, but the actual methodologies in Volume IV used to arrive at the scenarios might be of more general use. (Volume IV currently unavailable.)

Florida Atlantic University-Florida International University Joint Center for Environmental and Urban Problems and the UNF Center for Economic Education. 1979. Planning for Oil and Gas-related Industrial Development in Northeast Florida (symposium proceedings). Fort Lauderdale, FL: FAU-FIU Joint Center and the University of Northern Florida. Available from FAU-FIU Joint Center.

These proceedings examine potential onshore impacts of OCS development on Duval (Jacksonville) and Nassau counties and outline an oil and gas find scenario that determines the level of impacts on population, employment, the environment, and public facilities. They evaluate physical conditions for development and potential environmental impacts for five alternative sites (two for a gas processing plant and three for a permanent service base). Appendix B contains detailed community baseline information (population and employment characteristics, schools, wastewater systems, water supplies, solid waste disposal, transportation, and port facilities) which helps local planners identify underutilized capacities and pressures for expansion in the face of OCS development.

Alaska OCS Socioeconomic Studies Program, various dates and various authors. Anchorage, AK: Bureau of Land Management, Alaska OCS Office. Available from NTIS.

The Alaska OCS Socioeconomic Studies Program, as stated in its first annual report (Peat, Marwick, Mitchell and Company, First Annual Report, Synthesis of Findings, 1978, NTIS No. PB 281-536), "is a multi-year research effort which attempts to predict and evaluate the effects of Alaska OCS development upon the physical, social, and economic environments within the state."

The analysis addresses the differing effects among various geographic units including the state of Alaska, the several regions within which oil and gas development is likely to take place, and the various communities within these regions. The overall research method is multidisciplinary and based on three research components: (1) documentation of the "internal nature, structure, and essential processes of these various geographic units and the interaction among them," (2) preparation of alternative sets of assumptions regarding the location, nature, and timing of future OCS development environments and related activities, and (3) translation of future oil and gas development events into "quantities and forces acting on the various geographic units. The predicted consequences of these events are evaluated in relation to present goals, values, and expectations."

The program consists of a large number of individual reports, most dealing with one of the above mentioned aspects. Socioeconomic and physical baselines, for example, are either completed or in process for all affected communities and regions, as are petroleum development scenarios and their anticipated effects on many systems (transportation, socio-cultural, economic, and demographic) within these areas. Many of these studies are excellent, thorough analyses. Although they deal specifically with the regions and cultures of Alaska, their conceptual bases and methods are certainly applicable to the study of non-Alaskan regions. Their treatment of socio-cultural systems and impacts is especially well done. Several anthropological and sociological methods are employed in the assessments of socio-cultural baselines and impacts. (See for example Bennet, Heasley, and Huey, 1979, Northern Gulf of Alaska Petroleum Development Scenarios: Sociocultural Impacts, NTIS No. PB 300-699, Technical Report No. 26 of the Alaska Socieconomic Studies Program.)

There are also more general reports which do not fall into the above categories, such as a Visual Resources Management study and an extensive literature survey which is quite specific to Alaska. Two predictive methodologies developed as part of the program are listed in this bibliography under the "Methodologies" section (Peat, Marwick, 1979; and Huskey, Serow, and Volin, 1979), and one socioeconomic impact study is included under "General Case Studies" (Sevy, 1979).

Peat, Marwick, Mitchell, and Company is responsible for the largest percentage of the studies comprising this program. Other authors include Dames and Moore, Alaska Consultants, Inc., several departments of the University of Alaska, and several individual researchers. Inquiries about the program should be directed to Program Coordinator, Socioeconomic Studies Program, Alaska OCS Office, P.O. Box 1159, Anchorage, Alaska 99510. Most of the reports are also available through NTIS. See Alaska Socioeconomic Studies Program titles for NTIS numbers.

Mathematical Sciences Northwest, Inc. and Alaska Consultants, Inc. 1976. A Social and Economic Impact Study of Offshore Petroleum and Natural Gas Development in Alaska: Phase II. Anchorage, AK: Bureau of Land Management, Alaska OCS Office. Available from NTIS, No. PB 264-706.

This volume applies the techniques developed in Phase I (see Mathematical Sciences, 1976, in the "Impact Assessments" section) to project the economic and socioeconomic impacts that could occur in three small Alaskan communities (Yakutat, Dillingham, and Kotzebue) with potential for OCS development. Chapter 2 describes the structure and application of the input-output model used to predict economic changes attributable to OCS development. Chapters 3 through 8 present baseline inventory data for each town (including demographics, employment and income levels, community services, transportation, land use, land capability, housing conditions, and local government powers and finances).

Roles and Strategies for State and Local Decision Makers

Chorich, Martin. 1978. Cooking with Offshore Oil: A Handbook for California Local Government. Los Angeles, CA: USC Institute for Marine and Coastal Studies. Sea Grant Report No. USCSG-AS-01-78. Available from NTIS, No. PB 288-656.

Sections I and II briefly describe the OCS leasing process and identify key impacts of concern to local government (i.e., air and water pollution, coastal land use conflicts, socioeconomic impacts, recreation, and the fishing industry), their sources, and local government responses to them.

Section IV - The Local Role in OCS Development: Describes the opportunities presented by a federal law for the participation of local governments in all phases of the leasing and development process (e.g., state and local permits, and the proposal of federal regulations, OCS operating orders, and lease stipulations).

Section V - The San Diego Experience: Describes actions taken by San Diego's local governments to protect their interests in OCS development.

Section VI - Appendices: Summarize federal OCS-related legislation and federal agencies' involvement in OCS development. It describes the Bureau of Land Management's OCS leasing system and public participation process. It contains copies of BLM lease stipulations and correspondence from local to federal agencies expressing local decision-making concerns, as well as resolutions and ordinances that local governments in California have developed in response to OCS activity.

The study provides no clear guidelines for local actions nor detailed explanations of the impacts of offshore and related onshore activities.

Criteria and Procedures Used in Siting OCS-Related Facilities

New England River Basins Commission. 1978. Case Studies in OCS Planning. Boston, MA: NERBC-RALI. Available from NERBC.

This volume describes and evaluates how four states used the NERBC Factbook and facility siting methodology (Methodology III).

Massachusetts used the methodology to identify all facilities that might be attracted to the state and to examine the siting possibilities of its entire coastline. Maine examined potential sites along its entire coastline for only one type of facility (deepwater terminals). Rhode Island studies one site in detail (the vacant Quonset Point/Davis Naval Air Station) to identify all of the facilities that it might attract. New York documented the developable sites available in the New York metropolitan area in order to market them for any industries that might find them attractive.

Instead of presenting a standardized methodology for OCS-related development, the book stresses the importance of accurate, authenticated information from which state and local planners can draw their own conclusions and modes of action.

Rooney-Char, A. and R.P. Ayres. 1978. Offshore Pipeline Corridors and Landfalls in Coastal Virginia. Gloucester Point, VA: Virginia Institute of Marine Science. Special Report in Applied Marine Science and Ocean Engineering No. 190 prepared for the Virginia Coastal Resources Management Program. Available from NTIS, No. PB 297-439.

This publication addresses well the technical planning considerations involved in determining the appropriate location of pipeline corridors through the coastal marine environment, given the likelihood of possible conflicts between industry's siting requirements and the use of coastal resources by the people of Virginia.

Chapter 2 - The Pipeline Corridor Siting Process: Outlines a methodology to locate generally suitable areas for corridors based on industrial siting considerations and anticipated environmental impacts on coastal resources. The study does not address political or institutional realities, socioeconomic factors, or site-specific considerations. Chapter 3 briefly describes the study area and various pipeline installation techniques.

Chapter 4 - Industrial Siting Considerations: Discusses natural features and other coastal activities (including fishing grounds and ship channels) that affect industry's decisions regarding cost, technical feasibility, and risks. The problem of acquiring onshore and offshore rights-of-way are considered; Table 2 is very useful in indicating the features or conditions most preferred by industry for pipeline construction.

Chapter 5 - Coastal Resource Siting Considerations: Discusses possible adverse impacts of pipelines on coastal resources and their uses which often restrain pipeline siting. Table 3 displays these probable impacts and general measures that industry can take to reduce them.

The final part of the report stresses the careful screening of candidate sites and the development of evaluation guidelines based on the above industrial and coastal resource considerations. It includes composite maps and "landfall tables" which identify and summarize siting considerations and potential environmental impacts.

The publication contains the following appendices:

1. Inventory Maps
2. Environmental Impacts and Mitigating Measures for Pipeline Activities in Coastal Virginia
3. Proposed Dredging Guidelines for Subaqueous Lands
4. Extracts from Wetlands Guidelines
5. Guidelines for the Preparation of Environmental Impact Statements
6. Inventory of Federal Lands

Rogers and Golden, Inc. and Alan Mallach Associates. 1978. Maryland Major Facilities Study: Executive Summary. Annapolis, MD: Maryland Department of Natural Resources, Energy and Coastal Zone Administration. Available from MdDNR.

This executive summary is an overview of the four volumes that describe the process and results of the Maryland study.

Volume 1 - Regional Screening and Conflict Resolution: Examines data pertaining to the study region in order to identify, on the basis of predetermined criteria, areas most likely to contain suitable sites for the development of specific major facilities. The process allows "systemic examination of the entire study region and logical isolation of optimal candidate areas for each individual facility." Three types of evaluation criteria are used: facility-related criteria (functional requirements and optimal site conditions), exclusion criteria (facilities preempted by existing development or in federal ownership), and potential restriction criteria (avoiding areas of concern to public policy). It discusses the identification and resolution of four types of conflict: facility-facility, facility-site, facility-policy, and policy-policy.

Volume 2 - Eastern Shore Power Plant Siting Study

Volume 3 - Economic, Fiscal, and Social Assessment Handbook: Describes the structure of the Economic and Fiscal Model employed to measure local economic effects, population and housing effects, and service delivery effects which provide information necessary for knowledgeable decisions. It also describes how social effects related to community structure and relations are assessed.

Volume 4 - Environmental Assessment Handbook: Provides a general outline of the approach used, including selected charts and a project evaluation worksheet employed by users of the Handbook.

REGIONAL INFORMATION

The following reports and studies deal specifically with North Carolina and the Mid-Atlantic and South Atlantic leasing regions.

Department of the Interior. nd. Draft Environmental Impact Statement, Proposed 1981 OCS Oil and Gas Lease Sale #56. New Orleans, LA: Bureau of Land Management, OCS Office. Available from BLM's OCS office.

Proposed lease sale #56 contains the tracts which will affect North Carolina. This is a standard draft EIS, containing most of the raw data about this particular lease sale that is necessary before planning can begin.

Bureau of Land Management, U.S. Department of the Interior. Unofficial reproduction of typescript of "Notice of Sale/Outer Continental Shelf (OCS)/Oil and Gas Lease Sale No. 56, Offshore the South Atlantic States." Washington, D.C.: Bureau of Land Management, June 29, 1981.

> This 26-page document is a copy of the Oil and Gas Lease Sale No. 56, which includes tracts off the North Carolina coast, and which was held in New Orleans on August 4, 1981. The notice of sale describes the filing of bids by oil and gas companies, the method of bidding, and the list of all tracts available for sale. The lease terms, royalty on production and other stipulations are also detailed in the notice. The document provides necessary information about the lease sale and its requirements for bidders, and could be of interest to planners and local officials desiring specific details about this particular sale.

Jackson, J.B. 1980. Outer Continental Shelf Oil and Gas Activities in the South Atlantic (U.S.) and their Onshore Impacts: A Summary Report. Reston, VA: U.S. Geological Survey. Available from the USGS Oil and Gas Information Program, Open File Report 80-626.

> This short report provides basic, up-to-date information on the current status of OCS development in the Southeast. Updated reports are to be issued approximately every six months. The four short sections it contains are:
>
> 1. Offshore Oil and Gas Resources of the South Atlantic Region - Summarizes the geology of the OCS in the South Atlantic region and includes a brief explanation of how hydrocarbon potential is estimated and a table of current resource and reserve estimates.
>
> 2. Magnitude and Timing of Offshore Development - A short history of OCS activity in the South Atlantic, including projections for the near future.
>
> 3. OCS Oil and Gas Transportation Strategies - Since the transport of oil and gas ashore for processing, refining, and distribution is one of the most complex and difficult parts of the OCS development process, early planning for it is advocated. Mechanisms which involve the functions of the Regional Technical Working Groups are discussed.
>
> 4. Nature and Location of Nearshore and Onshore Facilities - Describes the onshore OCS support activity that has occurred in three areas of Georgia.
>
> The lengthy appendices include several annotated bibliographies and a brief but helpful explanation and discussion of the BLM's Intergovernmental Planning Program.

Macpherson, G. and C. Bookman (Rogers and Golden, Inc.) 1979. Outer Continental Shelf Oil and Gas Activities in the Mid-Atlantic and their Onshore Impacts: A Summary Report. Reston, VA: U.S. Geological Survey. Available from USGS Oil and Gas Information Program, Open File Report 80-17.

Chapter 1 describes the geological setting of the Mid-Atlantic lease region, the hazards and constraints to offshore development, and the estimation of hydrocarbon potential.

Chapter 2 discusses the magnitude, timing, and result of exploration activity since the lease sale.

Chapter 3 describes BLM's Intergovernmental Planning Program for OCS Oil and Gas Leasing, Transportation and Related Facilities and focuses on the analysis of oil and gas transportation strategies.

Chapter 4 presents the history and current status of onshore activities complementary to offshore exploration (i.e. the support bases at Atlantic City, N.J. and Davisville, R.I.) and their projected activity in the near future. The description includes physical facilities, levels of employment, and housing demand pressures.

Appendix A - Geological Setting
Appendix B - Estimating Oil and Gas Resources
Appendix C - Intergovernmental Planning Program of the BLM
Appendix D - Federal, State, and Local OCS-related Studies (a good annotated bibliography of the studies dealing with OCS development in the Mid-Atlantic region)

Deis, J. (Rogers, Golden and Halpern, Inc.) 1980. Update 1, June 30, 1980 -- Outer Continental Shelf Oil and Gas Activities in the Mid-Atlantic and their Onshore Impacts: A Summary Report, November 1979. Reston, VA: U.S. Geological Survey. Available from USGS's OCS Oil and Gas Information Program, Open File Report 80-17 (update).

Describes offshore and related onshore activity that has occurred since the initial Summary Report.

Salzman, M.A. (Rogers, Golden and Halpern, Inc.) 1980. Atlantic Index/ January 1975 - November 1980. Reston, VA: U.S. Geological Survey. Available from USGS's OCS Oil and Gas Information Program, Open File Report 80-1202.

This index presents information on the OCS leasing process and the most recent leasing schedule. It includes sections on the history of the various Atlantic lease sales, the documents and data produced for each sale, federal programs associated with OCS leasing, and state and local involvement in the leasing process. Appendices cover directory listings of headquarters and regional federal agencies, Atlantic Region state agencies, federal depository libraries, additional federal information sources, and abbreviations and acronyms. This is timely and comprehensive information about the status of OCS leasing in the Atlantic as well as a useful bibliographic source for planners.

Benton, J., R. Homman, and T. McDowell. Outer Continental Shelf Oil and Gas Information Program: Atlantic Index (January 1975 - April 1979): An Annotated Guide to Reports and Documents Used by the Federal Government in the Decisionmaking Process for Leasing, Exploration, Development, and Production of the Outer Continental Shelf. Reston, VA: U.S. Geological Survey, May 1979.

As required by law, this Index was issued by the U.S. Geological Survey and the Bureau of Land Management in 1979 to keep states and local governments informed about the proposed programs and plans surrounding the oil and gas leasing program in the Atlantic coastal area. It includes general background materials and specific information about the proposed OCS planning schedules, environmental impact statements, lease sales, exploration plans and environmental reports, and drilling permits for exploration in the Atlantic Ocean. Information about development and production plans (including environmental reports, assessments and impact statements) and pipeline permits have not been prepared because marketable mineral resources had not yet been discovered when the Index was prepared. Although the volume contains several excellent flowcharts describing the OCS decision-making process and provides good background data about the Atlantic coast, it is over two years since its publication, and the reader must look to more current sources of data for recent coastal activity descriptions.

South Atlantic Regional Technical Working Group. South Atlantic Regional Transportation Management Plan. New Orleans, LA: Bureau of Land Management OCS Office, June 1981.

This volume is the end product of the work of the South Atlantic Regional Technical Working Group (RTWG) in conjunction with the South Atlantic states and the Bureau of Land Management. The purpose of the volume is to identify acceptable land and water areas in each leasing region for transporting OCS oil and gas for local use or for processing. The volume explains both the federal and the state pipeline regulatory framework and how the planning system was designed on three levels to accommodate the wide regional differences of OCS oil and gas activities in the South Atlantic region. A brief but very useful section describes which North Carolina state agencies have permit or other requirements concerning pipeline routing and construction in state waters (within the three-mile limit) or onshore. Another valuable section describes the North Carolina Level I Plan in which 14 categorical areas have been identified as containing environmental or sociocultural values, risks, or concerns which could be impacted by activities associated with OCS oil and gas transportation and coastal energy developments.

Resource Planning Consultants, Inc. 1976. Identification and Analysis of Mid-Atlantic Onshore OCS Impacts. Washington, D.C.: Federal Energy Administration, Office of Energy Resource Development. Prepared for the Middle Atlantic Governors' Coastal Resources Council (MAGCRC). Available from NTIS, No. PB 254-925.

This document reviews six reports which analyze and project potential onshore impacts in the Mid-Atlantic states from New York to Virginia.

Chapter 2 contains a detailed comparison of the studies' critical assumptions regarding resource estimates, development timetables, and facility requirements, and the methodologies used to project impacts.

Chapter 3 investigates the applicability of the six studies to the planning information needs of the individual MAGCRC states.

Chapter 4 presents a summary of the major decision steps and timing of state government involvement in OCS decisions under current regulations and the major policy options proposed for changing these regulations.

Chapter 5 outlines additional study needs to arrive at more adequate impact estimation methodologies, to address impacts that have been ignored, and to propose changes in decision policies.

The appendices provide more detailed analyses of the individual studies, including their purposes, key assumptions, and impact projections:

Appendix A - Potential Onshore Effects of Oil and Gas Production on the Atlantic and Gulf of Alaska OCS (Volume IV of CEQ's OCS Oil and Gas - An Environmental Assessment).

Appendix B - A Socioeconomic and Environmental Inventory of the North Atlantic Region. 1974. The Research Institute of the Gulf of Maine (under contract to BLM).

Appendix C - A Study of the Socioeconomic Factors Relating to the Outer Continental Shelf of the Mid-Atlantic Coast. 1975. University of Delaware College of Marine Studies.

Appendix D - Mid-Atlantic Regional Study - An Assessment of the Onshore Effects of Offshore Oil and Gas Development: Summary and Analysis. 1975. Woodward-Clyde Consultants (for the American Petroleum Institute).

Appendix E - Draft Environmental Impact Statement for Proposed Outer Continental Shelf Mid-Atlantic Oil and Gas Lease Sale No. 40: Summary and Analysis. Bureau of Land Management.

Appendix F - A Study of New Use Demands on the Coastal Zone and Offshore Areas of New Jersey and Delaware. 1976. Office of Technology Assessment, Ocean Assessment Group.

Appendix G - Summary of Public Hearings for the BLM's DEIS (including private organization comments and individual, local government, and state government comments).

Goodman, J. and P. Klose. 1978. Environmental Planning for Offshore Oil and Gas. Volume V: Regional Status Reports, Part II: Mid and South Atlantic. Washington, DC: Conservation Foundation, U.S. Fish and Wildlife Service, Biological Services Program, FWS/OBS-77/162. Available from USFWS, National Coastal Ecosystems Team.

This is Part 2 of Volume V of the series of reports written by the Conservation Foundation for the U.S. Fish and Wildlife Service. The other parts of Volume V are regional status reports for (1) New England, (3) the Gulf Coast, (4) California, and (5) Alaska, Washington, and Oregon.

Each of the regional reports is divided into the following five sections:

1. a discussion of past and present OCS production
2. a description of OCS development and future potential, including industry schedule and anticipated future projects
3. the effects on living resources of accompanying actions
4. the socioeconomic interests, including the effects of anticipated development and regional interest in OCS, and
5. a "Regional Information Analysis," an annotated bibliography of publications of regional import.

Kilpatrick, J.E. 1975. The Role of North Carolina in Regulating Offshore Petroleum Development. Chapel Hill, NC: University of North Carolina Sea Grant. Available from UNC Sea Grant, Report No. UNC-SG-75-09.

This publication examines existing laws which may be applicable to the regulation of offshore development, concentrating on the state's role in leasing decisions and the protection of aquatic and onshore environments. It discusses the problem of delineating North Carolina's offshore boundaries and the geologic prospect of oil development off the North Carolina coast. It also provides a description of the roles of international law, the Submerged Lands Act, the N.C. Oil and Gas Conservation Act, the Rivers and Harbors Act, dredge and fill law, the N.C. Oil Pollution Control Act, the N.C. Coastal Area Management Act, the Outer Continental Shelf Lands Act, the Federal Water Pollution Control Act Amendments of 1972, the National Environmental Protection Act, and the Federal Coastal Zone Management Act of 1972.

The state's legitimate stake in the following planning issues is defined:

1. What is the best oil drilling technology?
2. Will regulations governing federal offshore drilling be as stringent as the state's regulations?
3. What are the precise plans for oil spill control?
4. Where will the associated complex of underwater pipes, storage tanks, and refineries be located?

It presents no planning strategies for dealing with onshore impacts, only the legal framework in which they operate.

Institute for Transportation Research and Education (University of North Carolina). 1980. Coastal Energy Transportation Study: An Analysis of Transportation Needs to Support Major Energy Projects in North Carolina's Coastal Zone. Phase I Report. Research Triangle Park, NC: ITRE.

This 181-page report summarizes the Phase I results of a two-phase North Carolina transportation study funded by the Coastal Energy Impact Program (CEIP) and conducted by the University of North Carolina's Institute for Transportation Research and Education (ITRE) during the 1980-82 period.

Phase I efforts identify and document the transportation facilities necessary to support major energy-related projects and facilities proposed for the 27 coastal counties in the state. Interviews were conducted in 1980 with key industry representatives and state and local coastal officials to help determine site locations, and valuable information is provided regarding major facilities, energy use scenarios, and an assessment of the transportation needs of these projects. Of particular importance is the identification and rating of fourteen potential sites at four coastal locations where OCS support bases could be located. Six sites (two in Wilmington, two in Southport, and two in Morehead City) are suggested for more detailed investigation. Information regarding pipeline transportation facilities and the major effects of their construction on the marine ecological system is also included.

This study, which also details the design for Phase II of the project, is an invaluable current reference tool for planners and government officials interested in the exact locations for potential energy-related projects and their transportation needs along the North Carolina coast.

Institute for Transportation Research and Education (University of North Carolina). 1981. Coastal Energy Transportation Study: An Analysis of Transportation Needs to Support Major Energy Projects in North Carolina's Coastal Zone. Summary Report, Phase I. Research Triangle Park, NC: ITRE.

This 30-page report is a summary of the full Phase I document listed above. It contains lists, maps and brief descriptions of the coal terminal sites, OCS support base sites, and key transportation projections and needs related to the rail, highway, air, water, pipeline, and marine terminal systems that could be affected by energy-related facilities proposed for the North Carolina coast. This is a clear, concise document which can be very useful for government officials, planners, and coastal residents interested in the details of possible energy sites and their potential transportation problems.

Institute for Transportation Research and Education (University of North Carolina). 1981. Coastal Energy Transportation Study: An Analysis of Transportation Needs to Support Major Energy Projects in North Carolina's Coastal Zone. Draft Phase II Report, Volume 1. Research Triangle Park, NC: ITRE.

This 66-page report summarizes a segment of the work done in Phase II of a two-phase transportation study conducted by the University of North Carolina Institute for Transportation Research and Education (ITRE) under Coastal Energy Impact Program funding. The volume briefly reports on the projected industry needs for coal export terminals and for OCS oil and gas development and production. Locational alternatives for coal export terminals and for OCS support bases comprise the remainder of the report. Important and timely information about shore support requirements, service bases, and the specific needs at these sites is included. Specific sites in four North Carolina towns (Morehead City, Wanchese, Southport, and Wilmington) are identified and mapped, and two sites are given top priority after the application of a set of 15 criteria to each site. This volume is an excellent reference source for persons wishing detailed information regarding coal and OCS support base sites on the North Carolina coast.

Institute for Transportation Research and Education (University of North Carolina). 1981. Coastal Energy Transportation Study: An Analysis of State and Federal Policies Affecting Major Energy Projects in North Carolina's Coastal Zone. Draft Phase II Report, Volume 3. Research Triangle Park, NC: ITRE.

This valuable volume identifies the most significant policies and requirements of the state and federal levels of government which may have an effect on the development of coal export terminals and OCS support bases in North Carolina. Although the OCS support bases and coal terminals are treated as transportation facilities by the Coastal Energy Transportation Study, this volume is divided into two major parts: the first explains the policies affecting the development of the facilities themselves, and the second details the policies affecting the transportation support of those facilities. Energy facility development policies include information regarding environmental impact analysis and the lengthy permitting process (including dredge and fill operations, air and water supply quality, and CAMA regulations and consistency review). The policies related to transportation and support needs and requirements for these facilities include water, rail, highway, and slurry pipeline data. In addition, an extremely useful set of appendices includes copies of several North Carolina statutes related to needed permits (i.e. dredge and fill, easements to fill, well construction, air quality review criteria, and others). Finally, the volume offers an invaluable bibliography and a list of contacts for OCS and coal development projects.

APPENDIX B:
SAMPLE ORDINANCES, RESOLUTIONS, AND POLICIES

This Appendix contains examples of local government ordinances, resolutions, and policies developed in areas confronted with OCS-related activities. They are drawn from Planning for Onshore Development: Discussion Papers, edited by Devon Schneider and published by the American Society of Planning Officials in 1977.

Material in this appendix includes:

- Santa Barbara County, California, "Statement of Policy Relative to the Location of On-shore Oil Facilities," 1967.
- City of New Bedford, Massachusetts, "Ordinance Establishing a Waterfront Industrial District," 1973.
- Northampton County, Virginia, "Planned Industrial District," 1976.
- Troy, Michigan, "Environmental Impact Statement," 1976.

Local planners should not view these materials as cookbook recipes to be followed slavishly, but rather as suggestive illustrations to help promote the flow of creativity in dealing with local needs.

Santa Barbara County, CA

April 12, 1967

STATEMENT OF POLICY RELATIVE TO THE LOCATION OF ON-SHORE OIL FACILITIES

WHEREAS, the oil industry anticipates a need for on-shore sites for oil and gas handling facilities to serve off-shore and coastal shelf production, and

WHEREAS, Santa Barbara County acknowledges the probable need for such on-shore facilities, and

WHEREAS, Santa Barbara County recognizes that its recreational and scenic resources, as well as its residential environment, represent the highest and best use of the land in this area and recognizes its responsibility to protect and preserve them;

BE IT RESOLVED THAT:

A. This policy shall apply to all applications for construction or expansion of oil and gas handling facilities in that portion of Santa Barbara County generally bounded by Point Conception on the west, the ridge line of the Santa Ynez mountains on the north, the Ventura County line on the east, and the three mile limit line on the south.

B. Any on-shore oil or gas handling facilities serving off-shore and coastal shelf production shall be compatible with the present and potential recreational and scenic resources and the residential environment of this area.

C. For clarification of terms the following definitions of oil and gas handling facilities shall apply to this policy statement:

Class I - Marine terminals including storage and loading equipment.

Class II - Tank farms for storage of oil and gas production to be shipped to marine terminals or to be transported by pipe lines.

Class III - Oil and gas handling facilities for the general purpose of separating water and gas (to include the fractionation of propane and butane), removal of impurities, and measuring.

Class IV - Refining of oil and gas products.

D. 1. The County will favor no more than one additional Class I facility to those now in existance.

2. The County will not favor any new Class II or Class III facilities within three miles of any existing facilities, not to be construed as an automatic approval of facilities where the spacing exceeds three miles.

3. Class IV installations will not be permitted.

E. The County will favor expansion of existing facilities onto adjacent lands provided all other criteria of this policy are observed. Consolidation of facilities on existing sites or on adjacent land will be favored as an alternative to establishment of new separate sites. The expansion of any existing facility shall carry the obligation to bring the existing part in conformity with these criteria.

F. Each application for an on-shore facility for the purpose of handling oil or gas production shall be considered on the basis of:

1. Appearance of facility from surrounding areas.
2. Impact of such facilities on the potential development of surrounding areas from the standpoint of noise, vibration, odor, air pollution, visibility, lighting, traffic, grading, flood and erosion control, land and water pollution, public safety, land use and similar effects.
3. Existing applicable ordinances.

G. The criteria for establishing the fact that the facility will be compatible are as follows:

NOISE AND VIBRATION: The level of noise at the property boundaries shall not exceed the ambient value prior to development. No vibration shall be perceptible at the property boundary without instruments.

ODOR: No odors of any kind shall emanate from the installation.

AIR POLLUTION: There shall be no visible emission of smoke. Exhausts from any combustion (excepting motor vehicles) shall contain no more than --------------------------------.

VISIBILITY: The installation shall be compatible with the potential surroundings by use of any or all of the following measures where applicable:

a) buffer strips

b) depressions, natural or artificial

c) screen planting and landscaping continually maintained, existing or not

d) camouflage and/or blending colors

LIGHTING: All lights shall be shielded so as not to shine on adjacent properties. Visible gas flares will not be permitted.

TRAFFIC: The traffic provisions of Article VI of Ordinance No.661 shall prevail.

GRADING: Grading shall be kept to an absolute minimum in order to preserve the natural contours of the land.

FLOOD AND EROSION CONTROL: Controls may be required to prevent erosion and flood damage.

LAND AND WATER POLLUTION: There will be no discharge of effluent which will contaminate land or water.

PUBLIC SAFETY: The safety of people and adjacent properties must be assured.

LAND USE: Each application shall be subject to the provisions of a specific ordinance under the PM zone designation. The time limitation of the PM designation to be equal to the development terms of each lease served, not to exceed five years.

CITY OF NEW BEDFORD, MASSACHUSETTS

IN THE YEAR ONE THOUSAND NINE HUNDRED AND SEVENTY-THREE

AN ORDINANCE

ESTABLISHING A WATERFRONT INDUSTRIAL DISTRICT

Be it ordained by the City Council of the City of New Bedford as follows: SECTION 1. That Title 9, Chapter 2 of the Code of the City of New Bedford, be amended by adding the following new sections:

SECTION 9-296 WATERFRONT INDUSTRIAL DISTRICT--USES.

Within any Waterfront Industrial District, as indicated on the Zoning Map,--no building or premise shall be used and no building or structure shall be erected which is intended or designed to be used, in whole or in part, for other than the following specified purposes:

1. Transformer station, pumping station, gas regulation station, telephone exchange station and other public utility uses.

2. Off-street parking facilities at grade or in purpose-built structure for the storage of registered motor vehicles.

3. Water freight terminal facilities for the handling and temporary storage of waterborne commodities including docks, piers, wharves, and gantries.

4. Businesses engaged in wholesaling, warehousing and storage of commodities where such business shall be primarily reliant upon a waterfront location or shall be in direct support of industrial uses which require a waterfront location.

5. Businesses engaged in the sale, distribution or storage of grain, petroleum products, building materials and industrial machinery provided that such business shall be primarily reliant upon a waterfront location or shall be in direct support of an industrial use which requires a waterfront location.

6. Businesses engaged in salvaging, dismantling and reprocessing of scrap and waste materials including building materials, motor vehicles, machinery and equipment, paper, rags or any other discarded material provided that such business shall be primarily reliant upon a waterfront location.

7. Businesses engaged in manufacturing, assembling, processing, fabricating, or otherwise adapting for sale of products including research, development or testing laboratories and facilities provided that such business shall be primarily reliant upon a waterfront location or shall be in direct support of an industrial use which requires a waterfront location.

8. Businesses engaged in the retail sale of goods and services clearly incidental to a permitted principal use.

9. Businesses engaged in the sale of food and beverages, including alcoholic beverages.

10. Any use which is permitted in the Industrial "A" District, provided that such use shall be primarily reliant upon a waterfront location.

11. No building or structure shall be erected and no building or premise shall be used which is intended or designed to be used in whole or in part for residential purposes.

SECTION 9-297 Dimensional Regulations.

1. Height. No building shall be in excess of one hundred (100) feet. The above provision as regarding height shall not apply to spires,

cupolas, belfries, chimneys, flag or radio poles, gasometers, grain elevators not to penthouses enclosing stairs or elevators, water tanks, or scenery left occupying an aggregate area of twenty-five (25) percent or less of the ground area of the buiilding; nor to towers including water towers, and hose towers which may occupy twenty-five (25) percent or less of the ground area of the building.

2. Setbacks. No part of any building shall be constructed closer than ten (10) feet from any street line or lot line. No part of any building shall be constructed closer than five (5) feet to bulkhead or face of a wharf.

Provisions in Section 9-250 shall apply to this section.

3. Percentage of Lot Occupancy. No building or group of buildings on a lot shall occupy more than fifty (50) percent of the area of the lot.

4. Courts. The provisions set forth in Section 9-252 shall apply.

5. No part of any building shall be erected to a height in excess of one and three-quarters (1-3/4) times the horizontal distance from its face to the opposite street line except that a parapet wall may extend above such height not more than three (3) feet.

SECTION 2. This ordinance shall take effect in accordance with the provision of Chapter 43 of the Generals Laws (Ter. Ed.).

IN CITY COUNCIL, November 20, 1973
Passed to a second reading.
Ellen M. Gaughan, City Clerk

IN CITY COUNCIL, December 6, 1973
Ellen M. Gaughan, City Clerk
Passed to be ordained - Yeas 9, Nays 0.
Rule 40 waived
Presented to the Mayor for approval December 7, 1973. Ellen M. Gaughan
City Clerk
Approved December 7, 1973. John A. Markey, Mayor
A true copy, attest: ____________________ City Clerk

Northampton County, VA

Excerpts from: An Ordinance to Amend the Northampton County Zoning Ordinance by Adding a Planned Industrial District, PI-1...etc.
Adopted by the Northampton County Board of Supervisors, July 1, 1976.

ARTICLE 4A - PLANNED INDUSTRIAL DISTRICT PI-1

Statement of Intent

(a) The planned industrial district is intended to permit the development of large scale and comprehensively planned heavy industrial facilities on contiguous acres of land under unified control. The standards and procedures of this section are designed to permit the harmonious and efficient layout of uses, structures, circulation and utilities within the planned industrial district and to insure that such development does not adversely affect adjoining properties of the County in general.

. . .

4A-1 USES PERMITTED BY RIGHT

The following uses shall be permitted subject to all other requirements of this ordinance as a matter of right in Planned Industrial District PI-1:

4A-1-1. Truck, rail and marine terminals.

4A-1-2. Mixing of concrete and the manufacturing of concrete products.

4A-1-3. Fabrication of metal products such as pipe, vessels, ducts and storage tanks.

4A-1-4. Fabrication of marine structures and platforms.

4A-1-5. Fabrication of modular industrial plants, excluding nuclear power plants.

4A-1-6. Assembly of machinery and equipment.

4A-1-7. Conservation areas.

4A-1-8. Growing of forest, field and vegetable crops.

4A-1-9. Accessory uses and structures, such as but not limited to, the following:

4A-1-9(a) Employee and visitor vehicular parking, subject to Article 6-6. "Minimum off-street parking."

4A-1-9(b) The storage of materials to be processed or already processed by a permitted principal use on the premises.

4A-1-9(c) Sale and service of goods produced or processed by a permitted principal use on the premises.

4A-1-9(d) Temporary buildings, trailers and vehicles incidental to permanent construction work on premises. Such structures shall not be placed on the site until a building permit has been issued and shall be removed within one (1) month of substantial completion or abandonment of construction.

4A-1-9(e) Facilities such as wires, lines, cables, pipes, storage tanks and pumps for the provision of maintenance of water, sewer, gas, electric, telecommunication or similar utility service to the premises and to adjacent properties.

4A-1-9(f) Railroad sidings serving the premises and adjacent properties.

. . .

4A-10 ENVIRONMENTAL AND PERFORMANCE REGULATIONS

4A-10-1 General - Processes and equipment employed and materials or goods used or stored shall be limited to those which are not objectionable or hazardous at or beyond the perimeter of the PI-1 District, by reason of odor, dust, smoke, fumes, glare, noise, vibration, refuse matter or water-carried waste.

4A-10-2. Ground Water - Construction, site preparation, processes and equipment employed shall be such as not to lower the ground water table measurably or cause the degradation of the ground water quality through salt water intrusion or other means at any place outside of the district boundaries.

4A-10-3. Controlled Material - The storage and use of hazardous or inflammable fuels, paints, chemicals and other materials shall be in conformity with federal, state, and local laws and regulations and shall be done in such a manner so as not to endanger persons or property.

4A-10-4. Prohibited Materials - No fissionable or other nuclear materials, or radium or other radioactive materials shall be collected or stored within the district, save and except encapsulated non-contaminated by-product materials used for industrial radiographic purposes.

4A-10-5. Erosion and Sedimentation Control - All provisions for soil erosion and sedimentation control shall comply with the provisions of the Northampton County Erosion and Sediment Control Ordinance.

. . .

4A-11. SUPPLEMENTAL CONSIDERATIONS AND REGULATIONS

Rapid development of employment facilities in Northampton County and the resulting impact on existing public facilities, housing, highways and other necessary public facilities and services could exceed the County's ability to provide for such facilities. Therefore, under authority of Article 6-9 of this ordinance and Section 15.1-491 of the Code of Virginia, as amended, the Governing Body may impose conditions, including reasonable employment limitations, to ease the effect of rezoning land to the PI-1 district on the general public.

. . .

4A-15-10 Standards for Preparation of the Final Plan of Development - Every final Plan of Development submitted shall contain the following information together with such additional information as the applicant may determine to furnish:

(a) Location of tract by an insert map at a scale of not less than one (1) inch equals two thousand (2,000) feet, indicating the scale, the north arrow, and such information as the names and numbers of adjoining roads, streams and bodies of water, railroads, subdivisions, towns, and magisterial districts or other landmarks sufficient to clearly identify the location of the property.

(b) A boundary survey of the tract by courses and distances. The boundary survey shall have a minimum field position closure with a ratio of error of one (1) in seventy five hundred (7500), and shall be certified on the Plan of Development by the surveyor.

(c) All existing and proposed streets and easements, their names, numbers and widths; existing and proposed utilities; water courses and their names; owners, zoning, and present use of adjoining tracts.

(d) Location, type, and size of vehicular entrance to the site, including written approval of same from the Virginia Department of Highways; existing and proposed roadways serving or to serve the site, including projections of the traffic reasonably anticipated to utilize said roadways.

(e) Location, type, size and height of fencing, retaining walls and screen planting.

(f) All off-street parking, loading spaces and walkways, indicating type of surfacing, size, angle of stalls, width of aisles, and a specific schedule showing the number of parking spaces provided and the number required in accordance with this article.

(g) Number of floors, floor area, height and location of each building and proposed general use for each building.

(h) All existing and proposed water facilities indicating all pipe sizes, types and grades, and the equipment and processes for obtaining water. Provisions for the prevention of harm to the ground water supply.

(i) All existing and proposed sanitary sewer facilities indicating all pipe sizes, types and grades and where and how discharge is to be accomplished, including the specifications of treatment mechanism and methods to be used in eliminating harmful discharge.

(j) Provisions for the adequate disposition of natural and storm water indicating location, size, types and grades of ditches, catch basins and pipes, and connections to existing drainage system. Provision for the adequate control of erosion and sedimentation, indicating the proposed temporary and permanent control practices and measures which will be implemented during all phases of clearing, grading, and construction.

(k) All shoreline alteration, including dredging, filling, and bulkheading. Provision for disposition of spoils. Provision for prevention of salt water intrusion. Provision for preservation of the ecology of the area and prevention of damage to the ground water supply.

(l) Existing topography with a maximum of two-foot (2 ft.) contour intervals. Where existing ground is on a slope of less than two percent (2%), either one-foot (1 ft.) contours or spot elevations where necessary, but not more than fifty (50) feet apart on a fifty-foot (50 ft.) grid.

(m) Proposed finished grading by contours supplemented where necessary by spot elevations.

(n) All horizontal dimensions shown on the site plan shall be in feet and decimals of a foot to the nearest one-hundredth of a foot; and all bearings in degrees, minutes and seconds to the nearest ten (10) seconds.

(o) Provisions for emergency medical services and facilities.

(p) Provision for fire fighting services and facilities.

(q) A statement setting forth the proposed number of persons to be employed on the tract. Provisions for minimizing the adverse effect upon the County of the influx of significant numbers of persons to be employed on the tract.

(r) Statement setting forth the tentative schedule for construction of the facilities within the district.

(s) A statement agreeing to abide by the terms of Northampton County Zoning Ordinance and the terms and representations of the Plan of Development or any amendment therof.

4A-15-11 Landscape Development and Screening Plan - A landscape development plan shall be submitted for approval as part of the Plan of Development. This Plan shall show: those natural topographic features such as water courses, large trees, tree groves to be preserved and those to be altered or removed; architectural peripheral areas abutting highways and/or residential or agricultural districts; and detailed landscape development plan for specific lots for which building permits are requested, including all required screening.

(a) Any part of the district not used for buildings or other structures, storage, or off-street parking, loading and maneuvering areas, drives, and pedestrian walks, shall be planted with appropriate ground cover, trees, flowers, shrubs, and grass lawns, all of which shall be properly maintained in a health condition at all times; provided, however, that with the approval of the Governing Body, areas may be devoted to agriculture or left in their natural condition.

(b) Where screening is required, all facilities shall be screened as much as possible from view of any adjacent property by planting or by ornamental wall, all of which shall be properly maintained.

(c) All required screening, whether planted or architectural, shall be properly maintained. Dead plant materials shall be removed within a reasonable time and replaced during normal planting season.

4A-15-12. Utilities Plan - A utilities plan shall be submitted for approval as a part of the Plan of Development. This shall show the size and the proposed location of all exterior lines and equipment. All utilities are encouraged to be underground, except control instrumentation and substations which must be screened by planting or ornamental wall; provided, however, that the requirements of this section may be modified by the Governing Body where there will be no adverse effect caused by said modification.

4A-15-13. Processes and Water Demands -

(a) Each applicant for a final Plan of Development shall be required to submit to the Governing Body as a part of the application, a qualified engineer's report describing the proposed operation, all machines, processes and water uses; the quantity of ground water which is to be used and the maximum quantity of ground water which can be drawn; and the projected effect upon ground water levels, quantities and supplies as determined by on-site pumping tests.

(b) Each applicant for a final Plan of Development shall be required to submit to the Governing Body as a part of the application, a qualified engineer's report describing the proposed operation, all machines, processes, products and byproducts, stating the nature and expected levels of emission or discharge to land, air or water of any liquid, solid, or gaseous effluent or electrical impulses and noise under normal operations, and the specifications of treatment mechanism and methods to be used in restricting the emission of dangerous or objectionable elements.

. . .

Article 6-9 CONDITIONS

In addition to the regulations herein provided for the respective zoning districts, the Governing Body may adopt as a part of an amendment to the zoning map reasonable conditions, provided that said conditions shall have been profferred in writing, in advance of of the public hearing on said amendment to the zoning map, by the owner of the property which is the subject of the proposed zoning map amendment, and provided that said conditions are accepted by the Governing Body as a condition to said amendment of the zoning map.

07.00.00 ARTICLE VII ENVIRONMENTAL IMPACT STATEMENT

07.00.01 An Environmental Impact Statement (EIS), providing the information and data specified herein, in the form described, shall be required . . .

07.00.02 (a) Whenever a project is proposed by a public agency, or by other agencies using public funds (excluding Troy Municipal Agencies), which significantly affects the quality of the human environment; or

07.00.03 (b) Whenever a project is proposed which, in the opinion of the City Manager, significantly affects the municipal service systems (transportation, waste water systems, potable water supply systems, storm drains, police services, fire services, library services, solid waste disposal services, emergency medical services); or

07.00.04 (c) When stipulated under the terms of this Chapter or other Chapters of the City Code; or

07.00.05 (d) When required by the City Council or the City Plan Commission in order to assist in their consideration of a particular development proposal; or

07.00.06 (e) When a development proposal is submitted which, in the opinion of the City Plan Commission, constitutes a substantial departure from the intent of the Master Land Use Plan.

The requirements contained herein shall not relieve the projects sponsor from complying with EIS standards established by other public agencies having jurisdiction.

07.10.00 SUBMITTAL AND APPROVAL REQUIREMENTS

The sponsor of the project shall submit the following to the City Manager, on behalf of the City Council:

07.11.00 PRELIMINARY ENVIRONMENTAL IMPACT STATEMENT

A Preliminary Environmental Impact Statement shall be submitted in conjunction with requests for rezoning which would enable developments which, in accordance with the provisions of this Chapter, would require such submittals. A Preliminary Environmental Impact Statement shall consist of the applicable information or material required by the following portions of this Article:

(a) Section 07.20.00 Physical Conditions
(b) Section 07.30.00 Project Description
(c) Section 07.41.00 Impact Analysis: Systems, Sub-sections 07.41.01 through 07.41.04, inclusive.
(d) Other Sections or Sub-sections of this Article as determined by the Planning Director to be particularly important or necessary in order to provide adequate information regarding a specific rezoning or development proposal.

07.12.00 FINAL ENVIRONMENTAL IMPACT STATEMENT

A Final Environmental Impact Statement, including all applicable provisions of this Article, shall be submitted in conjunction with applications for Site Plan Approvals, Special Use Approvals, or Building Permits for developments which, in accordance with the provisions of this Chapter, would require such submittals.

Prior to the granting of building permits for projects covered by this Article, provisions satisfactory to the City Council shall be made to assure the financing and/or installation of all road and utility improvements and the provision of additional services found, by the Environmental Impact Statement process, to be necessary to serve the project.

07.20.00 PHYSICAL CONDITIONS

07.20.01 (a) legal description of the subject property prepared by a registered surveyor or civil engineer accompanied by a survey map of said property (scale 1" = 100', unless otherwise provided).

07.20.02 (b) location map, (scale 1" = 800') indicating the location of the subject property in relation to the City thoroughfare system.

07.20.03 (c) zoning map, (scale 1" = 400') indicating the subject property and the zoning of adjacent properties for a radius of 1 mile.

07.20.04 (d) land use map (scale 1" = 200') indicating the subject property and land uses of adjacent properties for a radius of one-half mile.

07.20.05 (e) general development plan or schematic of the subject property (scale 1" = 100') and adjacent properties within 1,000 ft. of its property line.

07.20.06 (f) site conditions of the subject property (scale 1" = 100', unless otherwise provided) indicating

(1) Natural features such as trees, streams, bodies of water, flood plains, soil conditions and topography (maximum two (2) ft. contour interval)

(2) Location and size of existing facilities and utilities (thoroughfares, water service, sanitary sewer, storm drain, gas lines, electric lines, etc.)

07.20.07 (g) limitation applicable to the development of the property (if any) as a result of proximity to airports.

07.30.00 PROJECT DESCRIPTION

07.30.01 (a) Description of intended use(s) with site plans and building elevations. Final Environmental Impact Statement submittals shall include an architectural model, to indicate the scale and massing of buildings. The requirement for submittal of an architectural model may be waived by the City Manager, when it is determined that the proposed development will be similar to an existing development available for review, or otherwise of a nature whereby its scale, massing, and potential relationship to adjacent development can readily be determined without assistance of an architectural model.

07.30.02 (b) Calculations of the quantities of proposed elements or functions of the development by type (gross and net floor area: number of dwelling units by type and bedroom count, parking spaces required and provided, rights-of-way, landscaped area required and provided, etc.)

07.30.03 (c) Anticipated number of employees, residents, school children by school type, and senior citizens.

07.30.04 (d) Anticipated vehicular generation.

07.40.00 PROJECT IMPACT ANALYSES

A full analysis and description, prepared by registered engineers, architects, public safety specialists, public facility specialists, etc. as applicable, of the proposed project's required levels of service, as compared to the service levels available, and the means by which the sponsor intends to serve the proposed project and resolve any potential deficiencies, relative to the following facility and utility systems and services:

07.41.00 IMPACT ANALYSIS: SYSTEMS

07.41.01 (a) Thoroughfares - Information should include projections of traffic volumes generated on and adjacent to the site as a result of the proposed development, and traffic facility improvements proposed as a result of the project to properly accommodate these volumes.

07.41.02 (b) Water service facilities for supporting potable water supply, fire flows and other uses, expressed in average and peak hour needs.

07.41.03 (c) Waste water systems, including average and peak hour needs.

07.41.04 (d) Storm drains and retention facilites, including provisions for retention site landscaping and maintenance.

07.41.05 (e) Solid waste collection, storage and disposal systems.

07.41.06 (f) Power, heat and communication systems.

07.41.07 (g) School facilities.

07.41.08 (h) Transportation facilities and services other than private automobile.

Such Project Impact analyses and information should take into account the potential development of adjacent areas which may be developed to similar intensities.

07.41.20 The sponsor shall present evidence that he has informed other affected organizations or agencies of the potential impact of the proposed project on their facilities and services. In this regard, receipts or other communications shall be submitted from organizations such as power and communications utilities, school districts, aeronautics authorities, etc.

07.42.00 IMPACT ANALYSIS: SERVICES

The sponsor of the proposed development shall submit information as to the project's impact upon the following service activities, indicating the steps being taken to alleviate any potential deficiencies or problems, or to supplement municipal involvement therein.

07.42.01 Fire protection and prevention.

07.42.02 Public and private safety and security systems.

07.42.03 Emergency medical services.

07.42.04 Lighting on and adjacent to the site.

07.42.05 Recreation and leisure time facilities and activities, including library services.

07.43.00 IMPACT ANALYSIS: ECONOMICS

Overall analyses or information shall be presented indicating the public revenue benefits resulting from the proposed project, as compared to the costs in terms of services and utilities.

(4-26-76)

07.44.00 IMPACT ANALYSIS: NATURAL AND SOCIAL ENVIRONMENT

The sponsor of the proposed development shall submit information and comments which indicate public advantages unique to the proposed project, or unavailable except as a result of the project, and shall approach matters such as, but not limited to, the following:

07.44.01 Environmental improvements (landscaped areas, open space areas, other aesthetic benefits.)

07.44.02 Employment opportunities.

07.44.03 Service opportunities.

07.44.04 Residential opportunities.

07.44.05 Recreation and leisure time opportunities.

APPENDIX C:
NORTH CAROLINA ENVIRONMENTAL PERMITS

The following descriptions come from the North Carolina Environmental Permit Directory published in May 1981 by the N. C. Department of Natural Resources and Community Development's Office of Regulatory Relations:

1. State NPDES Permit
2. Permit for Waste Not Discharged into Surface Waters
3. Water Use Permit
4. 401 Water Quality Certification
5. Well Construction Permit
6. Sedimentation Control Plan
7. State Dredge and Fill Permit
8. CAMA Major Development Permit
9. Easement to Fill
10. Air Quality Permit
11. Oil Refining Facility Permit
12. Hazardous Waste Facilities Permit
13. Permit for Solid Waste Disposal
14. Geophysical Exploration Permit
15. Permit to Drill Exploratory Oil or Gas Well

1. STATE NPDES PERMIT

Type of Project:	Permit is required for any project involving the construction, alteration, or extension and/or operation of any sewer system, treatment works, or disposal system which would result in a discharge into surface waters. Permit also required for a pretreatment system which would discharge to a publicly owned treatment works.
Authority:	N.C. Gen. Stat. Chapter 143, Article 21, Paragraph 1
Regulations:	NCAC 2H .0100 - .0123
Requirements:	The State has full authority to administer the National Pollutant Discharge Elimination System (NPDES) Permit Program. Application shall be filed at least 180 days prior to new construction or expansion of existing facilities with the Division of Environmental Management, Permits and Engineering Branch. Separate application forms are available as appropriate for municipal, agricultural, manufacturing and mining, commercial, or pre-treatment discharges. Applicants for permits for new source discharges of industrial process wastewater in excess of 100,000 gallons per day, or 10 million gallons per day of cooling water, shall additionally submit an environmental assessment which describes the impact on waters of the area.

An on-site inspection is required and a pre-application technical conference is desirable. Public notice is circulated at least 45 days prior to any proposed final action and a public hearing may be held. Usual conditions include effluent limitation, monitoring program and periodic reports.

Sets of Plans: Application shall be submitted in triplicate for each type of facility. Applicants for projects requiring construction of control facilities must submit an engineering proposal in triplicate.

Process Time: Normally 90 to 120 days from receipt of completed application.

Permit Duration: Not to exceed 5 years. Modifications or extensions of existing permits shall be requested at least 180 days prior to expiration of permit.

Contact:

Appropriate Regional Office, or
Division of Environmental Management
Post Office Box 27687
Raleigh, NC 27611
(919) 733-7120

2. PERMIT FOR WASTE NOT DISCHARGED TO SURFACE WATERS

Type of Project: Permit is required for any project involving the construction, alteration, or extension and/or operation of any sewer system, treatment works or disposal system which does not discharge to surface waters. Includes septic tank systems above 3,000 gallons per day design capacity and land application systems. Septic tank systems of less than 3,000 gallon design capacity, except those involving industrial process wastewater, are the responsibility of the local health department.

Authority: N.C. Gen. Stat. Chapter 143, Article 21, Part 1; N.C. Gen. Stat. Chapter 130, Article 13.

Regulation: 15 NCAC 2H .0200 - .0217

Requirements: Application shall be filed at least 90 days prior to initiation of construction or award of contracts for construction with the Division of Environmental Management, Permits and Engineering Branch. Supporting information including plans and specifications are required for the following project types: sewers and sewer extensions; pumping stations; septic tank, ground absorption systems; spray irrigation or land application disposal systems and treatment works; and closed system or recycle disposal systems and treatment works.

An on-site inspection and a post-application technical conference may be required. Ground absorption facilities must be inspected prior to backfilling.

Sets of Plans: Applications shall be submitted in duplicate form for each type of facility with complete engineering plans and specifications. Two sets of plans are required for regular projects and three sets are required for federal and state grants projects.

Process Time: 90 day statutory time limit; normally 30 days from receipt of completed application.

Permit Duration: As deemed appropriate by the Director. Request for renewals must be submitted six months prior to date of expiration.

Contact: Appropriate Regional Office, or

Division of Environmental Management
Post Office Box 27687
Raleigh, NC 27611
(919) 733-7120

3. WATER USE PERMIT

Type of Project: Required for any person who withdraws, obtains, or utilizes surface water, groundwater, or both in excess of 100,000 gallons per day in an area designated as a "capacity use area" by the Environmental Management Commission. The existing capacity use area in the State is in the coastal area, including Beaufort, Pamlico, and Washington Counties and portions of Carteret, Craven, Hyde, and Tyrrell Counties.

Authority: N.C. Gen. Stat. Chapter 143, Article 21, Part 2

Regulations: 15 NCAC 2E .0100 - .0105; .0200 - .0208

Requirements: Application shall be filed prior to project initiation with the Division of Environmental Management, Permits and Engineering Branch. A pre-application technical conference is desirable and an on-site inspection will be conducted.

The application shall describe the purpose or purposes for which the water will be withdrawn or used and justify the quantity needed for each purpose. Notice is given to other water use permit holders in the affected area. Monthly monitoring, periodic reporting, and water level controls may be required.

Other activities, involving construction or installation of works of improvement, which may significantly affect the quantity or quality of water must be approved by the Environmental Management Commission. These include, but are not necessarily limited to: surface drainage projects, subsurface drainage projects, well mining projects, and excavation projects.

Process Time: Normally 30 days from receipt of completed application.

Permit Duration: As determined by the Commission but not to exceed the longest of the following: 5 years, or the duration of the existence of the capacity use area, or the period found by the Commission to be necessary for the reasonable amortization of the applicant's water using facilities. Permits are not transferrable without prior approval of the Commission, and water withdrawn under the terms of the permit may be used only for the purpose(s) set forth in the permit.

Contact: Appropriate Regional Office, or

Division of Environmental Management
Post Office Box 27687
Raleigh, NC 27611
(919) 733-7120

4. 401 WATER QUALITY CERTIFICATION

Type of Project: Any person engaged in an activity which may result in a discharge to navigable waters and requires a federal permit must obtain a certification that such discharge will be in compliance with applicable state water quality standards.

Authority: N.C. Gen. Stat. Chapter 143, Article 21, Part 1

Regulations: 15 NCAC 2H .0500 - .05025

Requirements: Application shall be filed prior to project initiation with the Division of Environmental Management, Permits and Engineering Branch. An application for a Corps of Engineers Section 404 permit is considered as an application for a water quality certification. Project description, nature of discharge, and maps are among the documentation which is required. Public notice is issued at least 30 days prior to proposed final action and a public hearing may be held.

Sets of Plans: The original and six copies of the application for certification must be submitted.

Process Time: 130 day statutory limit; normally 60 days.

Permit Duration: Not applicable.

Contact: Appropriate Regional Office, or

Division of Environmental Management
Post Office Box 27687
Raleigh, NC 27611
(919) 733-7120

5. WELL CONSTRUCTION PERMIT

Type of Project: Required for any person constructing a well with a design capacity of 100,000 gallons per day or greater, or of any well added to an existing well system if the combined system capacity is 100,000 gallons per day or greater. Permit may be required for any well constructed in an area where the Environmental Management Commission finds, after public hearings, that such a permit is necessary to protect public welfare, safety, and health. The use of any well for recharge, injection or disposal also requires a permit.

Authority: N.C. Gen. Stat. Chapter 87, Article 7

Regulations: 15 NCAC 2C .0001 - .0018

Requirements: Application should be filed 15 to 30 days prior to project initiation with the Division of Environmental Management, Permits and Engineering Branch. All persons in the business of drilling, boring, coring, or constructing wells must be registered. The location, design, and operation of the well must be approved prior to issuance of a permit. Construction standards and well maintenance provisions are specified and certain data and records are required.

Sets of Plans: Application submitted in duplicate.

Process Time: 15 day statutory limit; normally 7 days.

Permit Duration: Duration of well construction.

Contact: Appropriate Regional Office

6. SEDIMENTATION CONTROL PLAN

Type of Project: A sedimentation control plan is required for any land disturbing activity when the proposed activity is to be undertaken on a tract comprising one or more acres; if more than one contiguous acre is to be uncovered.

Authority: N.C. Gen. Stat. Chapter 113A, Article 4

Regulation: 15 NCAC 4B .0001 - .0023

Requirements: A sedimentation control plan for the land disturbing activity must be submitted to the field office Land Quality Engineer or local government with an approved program at least 30 days prior to project initiation. Land disturbing activity means any use of the land by any person in residential, industrial, educational, institutional, or commercial development, highway and road construction and maintenance that results in a change in the natural cover or topography and that may cause or contribute to sedimentation. Agricultural and silvicultural activities and those activities regulated under the Mining Act of 1971 are exempted.

Control measures must be planned, designed and constructed to provide control for the calculated peak rates of runoff from a 10 year frequency storm. Plans should contain landscape architectural and engineering drawings, maps, assumptions, calculations, and a statement describing the proposed development of the site; and measures planned to meet mandatory standards, performance standards, and downstream protection of stream banks and channels.

Changes, modifications, or conditions may be required before plan approval. On-site inspection may be held during construction.

Sets of Plans: One set of plans is required.

Process Time: 30 day statutory limit; normally 15 days.

Permit Duration: Plan shall be in effect during construction and maintenance of proposed activity. Any changes must be reviewed and approved.

Contact: Appropriate Regional Office, or

Division of Land Resources
Post Office Box 27687
Raleigh, NC 27611
(919) 733-4574 , or
Local government with approved ordinance

7. STATE DREDGE AND FILL PERMIT

Type of Project: Any project involving construction or dredge and fill activities in estuarine waters, tidelands, marshlands, or state-owned lakes requires a permit.

Authority: N.C. Gen. Stat. Chapter 113, Article 17

Regulations: 15 NCAC 7J .0800 - .1024

Requirements: Application forms are available and may be filed with the Office of Coastal Management in Raleigh or the regional field office prior to project initiation. The joint application form includes other potential permits: CAMA Major Development Permit; Corps of Engineers' Section 10 and 404 Permits, Easement to fill on state-owned lands; and 401 Water Quality Certification. In addition to a completed application, specific standards for submission of work plats must be followed and a copy of deed or other instrument of ownership must be included. Additional information may be requested.

Any project needing a state dredge and fill permit and Corps 404 permit may qualify for a General 404 permit.

This will be determined automatically and the General 404 permit will be issued if state requirements are met.

The applicant is responsible for notifying each adjacent riparian landowner, and landowners have 30 days from the date of notification in which to comment. An on-site investigation is conducted and a field report is prepared. The application and field report are circulated to interested state agencies for review and comments.

The regulations also provide provisions for an expedited procedure for an applicant to request and receive a special emergency dredge and fill permit where life and structural property is in imminent danger as a result of rapid, recent erosion or sudden failure of a man-made structure.

Sets of Plans: One copy to Office of Coastal Management, one to Wilmington District Corps of Engineers, and one for applicant.

Process Time: 90 day statutory limit; normally 55 days.

Permit Duration: The permit will expire on December 31, two years subsequent to the year of issuance. Permits may be renewed for periods not to exceed one year upon written request.

Contact: Coastal Consultant, Regional Field Office , or

Office of Coastal Management
Post Office Box 27687
Raleigh, NC 27611
(919) 733-2293

8. CAMA MAJOR DEVELOPMENT PERMIT

Type of Project: The Coastal Area Management Act (CAMA) stipulated that major development permits are required for all land disturbing activities within designated areas of environmental concern (AEC) throughout the 20-county coastal area. Areas of environmental concern include marshlands, tidelands, shoreline and waters of the estuarine system; beaches, dunes, flood plain, and inlets of the ocean hazard area; public fresh water supply areas; and fragile natural and cultural resource areas. Development other than major, termed minor development, requires a permit from the local in an AEC jurisdiction where the development is to be located.

Authority: N.C. Gen. Stat. Chapter 113A, Article 7, Subsection 118

Regulations: 15 NCAC 7J .0100 - .0200

Requirements:	Application for CAMA major development permit must be made to the Office of Coastal Management in Raleigh, or the respective regional field offices in the coastal area. Major development is defined as any development which: (a) requires permission, licensing, approval, certification or authorization in any form from the Environmental Management Commission, Mining Control Board, or the Departments of Human Resources, Natural Resources and Community Development, or Administration; (b) occupies a land or water area in excess of 20 acres; (c) contemplates drilling for or excavating natural resources on land or under water; or (d) occupies on a single parcel, a structure(s) in excess of a ground area of 60,000 square feet. General and specific use standards concerning development types in each respective area of environmental concern are specific in the regulations. Minor development, any development other than major, may require a permit which is administered by the local government having jurisdiction in the proposed development area. Application forms and $10.00 fee for CAMA major development permits should be submitted well in advance of the planned construction date to the Office of Coastal Management in Raleigh or regional field offices. The application must include: location and description of the project; land type, disposal area, and construction equipment; land classification in CAMA local land use plan; current and future use of project area; and be accompanied by a location map and work plat drawn to specified standards and showing plan view and cross sectional view. The applicant must also furnish a copy of the deed or other instrument by instrument by which title to the property is claimed or permission by the owner is given. Once the application is determined to be complete, an on-site investigation is conducted and field report prepared. The application and field report are sent to state agencies for review and comment, and a notice is published in the local newspaper of circulation in the project area.
Sets of Plans:	One copy to Office of Coastal Management, one to Wilmington District Corps of Engineers, and one for the applicant.
Process Time:	90-day statutory limit with 90-day possible extension; normally 50 days.
Permit Duration:	Duration of land disturbing activity.
Contact:	Coastal Consultant, Regional Field Office, or Office of Coastal Management Post Office Box 27687 Raleigh, NC 27611 (919) 733-2293

9. EASEMENT TO FILL (LANDS BELOW NAVIGABLE WATER)

N.C. Gen. Stat. Chapter 143, Article 36, Subsection 341; 1 NCAC 6B .0501-.0512, .0601-.0610

Easements to fill are required for all filling activities in navigable waters where land is raised above the normal high water mark. The state claims title to all lands below the mean high water mark. Fill may only be placed in navigable waters by a riparian owner immediately adjacent to their property. A written application can be filed with the State Property Office or, since a state dredge and fill permit will be required, the joint-application form for coastal permits can be used. Notice to adjacent riparian owners with a 30-day comment period is required and can be met by similar notice for the state dredge and fill permit. Easements are also required for cable or pipeline corridors in or on lands below navigable waters. An administrative charge of $100.00 must accompany the application.

Contact:

Department of Administration
State Property Office
116 West Jones Street
Raleigh, NC 27611
(919) 733-4346

10. AIR QUALITY PERMIT

Type of Project:	Required for any person who establishes or operates any air contaminant source; equipment which may result in emissions of air contaminants or is likely to cause air pollution; or construction or installation of any air-cleaning device. A permit may be required for construction or modification of a complex source which includes such projects as shopping centers; sports complexes; drive-in theaters; parking lots and garages; residential, commercial, industrial, or institutional developments; and airport facilities. Projects are also reviewed for categories of sources involving federal New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, and Prevention of Significant Deterioration of Air Quality regulations.
Authority:	N.C. Gen. Stat. Chapter 143, Article 21B
Regulations:	15 NCAC 2H .0600 - .0608; 15 NCAC 2D .0800 - 0804; and 15 NCAC 2D .0531
Requirements:	Application for a permit to construct and operate air pollution abatement facilities, air contaminant sources, and/or complex sources should be made as soon as the construction designs are complete and must be filed with the Division of Environmental Management, Permits and Engineering Branch. Detailed engineering plans and specifications are required. If the proposed source is subject to a significant deterioration (PSD) permit it will be processed concurring

with the state air quality permit. A pre-application monitoring period may be required for a PSD permit and a public hearing may be required.

Ambient air quality standards, emission control standards, regulations for nonattainment areas, and requirements for monitoring and reporting are specified by reference to the regulations.

Jurisdiction for air quality permits in Buncombe and Haywood or Mecklenburg and Forsyth Counties has been delegated to respective local air pollution control agencies.

Sets of Plans: Application should be made in triplicate with associated engineering plans and specifications.

Process Time: Normally 60 days with a 90 day statutory limit for state air quality permit; for PSD, may range from 90 to 180 days.

Permit Duration: State air quality permit may be issued for a period not to exceed 5 years. PSD permit is for duration of operation as conditioned by the permit.

Contact: Appropriate Regional Officer, or

Division of Environmental Management
Post Office Box 27687
Raleigh, NC 27611
(919) 733-7120

11. OIL REFINING FACILITY PERMIT

Type of Report: Required prior to the construction or operation of an oil refining facility.

Authority: N.C. Gen. Stat. Chapter 143, Article 21A, Part 4

Regulations: 15 NCAC 1F .0001 - .0013.

Requirements: Application must be filed with the Assistant Secretary for Natural Resources. The application must address 16 specified elements including applicant's interest and experience in oil refining operations, applicant's financial condition, full description of facility's operation plans and procedures for minimizing adverse impacts of spills and discharges and an assessment of construction and operation impacts on wildlife, fisheries, air quality, water quality, and publicly owned parks, forests or recreation areas. Additionally, two sets each of the most current drawings, maps, plans, and specifications concerning facility construction and operation as well as the transfer of oil.

The applicants will be notified within 30 days whether the application is complete or incomplete. If incomplete, additional information will be requested. Within 45 days of completed application, a public notice is provided which includes a date for public hearing. The hearing must be held between 45 and 60 days after the date of the public notice and the record remains open 30 days after the close of the hearing. The permit decision must be made within 45 days from the close of the record.

The permit will not be effective until the necessary water and air quality permits are obtained. An annual report of specified aspects is required on February 1 of each year.

Sets of Plans: One application and two sets of drawings, maps, plans and specifications.

Process Time: Approximately 160 days.

Permit Duration: Duration of activity as conditioned by permit.

Contact:
Division of Environmental Management
Post Office Box 27607
Raleigh, NC 27611
(919) 733-7120

12. HAZARDOUS WASTE FACILITIES PERMIT

N.C. Gen. Stat. Chapter 130, Article 13B; 10 NCAC 10F .0001-.0027.

Any activity involving the storage, collection, processing, treatment, recycling, recovering or disposal of hazardous waste must be permitted by the Solid and Hazardous Waste Management Branch. The program is essentially the same as defined in Title 40, Chapter 250 of the Code of Federal Regulations which implements the federal Resource Conservation and Recovery Act. In addition to environmental and public health standards concerning facility siting and operation, standards must be met regarding contingency plans, emergency procedures, monitoring and record keeping, personnel training, financial responsibility, and post-closure plans. Normal processing time is 90 days.

Contact:
Department of Human Resources
Environmental Health Section
Solid and Hazardous Waste Management Branch
Post Office Box 2091
Raleigh, NC 27602
(919) 733-2178

13. PERMIT FOR SOLID WASTE DISPOSAL

N.C. Gen. Stat. Chapter 130, Article 13B; 10 NCAC 10C .0100

No person may establish a solid waste disposal facility without first obtaining a permit. Regulatory standards must be met for sanitary landfill, refuse site, or solid waste incinerator. All solid waste must be stored, collected, transported, recycled, and disposed of in accordance with the regulations. The application must contain detailed information characterizing the site and plan of operation. An on-site inspection and approval of the plan of operation are required. Periodic inspection during operation will be undertaken. Monitoring is required for surface and ground waters. Site must also be in conformance with local zoning regulations. Normal processing time is 60-90 days.

Contact:
Department of Human Resources
Environmental Health Section
Solid and Hazardous Waste Management Branch
Post Office Box 2091
Raleigh, NC 27602
(919) 733-2178

14. GEOPHYSICAL EXPLORATION PERMIT

Type of Project:	A permit is required to conduct geological, geophysical, and other surveys and investigations including seismic methods for the discovery of oil, tar, or other mineral prospects.
Authority:	N.C. Gen. Stat. Chapter 113, Article 27
Regulations:	15 NCAC 5C .0001 - .0028
Requirements:	Application by letter must be filed at least 10 days prior to geophysical operations with the Director of the Division of Land Resources. A detailed map must be included showing the exact area in which exploration will be conducted. Each exploration crew will be assigned a seismic agent who shall be present during all operations. The seismic agent must prepare and submit daily reports. A fee not to exceed $480 per month plus expenses not to exceed $10 per day will be charged to the geophysical operator to cover the salary of the seismic agent. A surity bond of $5,000 for one crew or $25,000 for more than one crew is required and the operator must have public liability insurance.
Sets of Plans:	One application required.
Process Time:	Normally 10 days.

Permit Duration: Permit duration is limited to 6 months from issue date, but may be renewed for not more than two additional 90-day periods. Application for renewal may be made in letter form.

Contact:
Division of Land Resources
Post Office Box 27687
Raleigh, NC 27611
(919) 733-4574

15. PERMIT TO DRILL EXPLORATORY OIL OR GAS WELL

Type of Project: A permit is required to conduct any exploratory drilling for oil and gas at any location in the state.

Authority: N.C. Gen. Stat. Chapter 113, Article 27

Regulations: 15 NCAC 5D .0001 - .0011

Requirements: Prior to making any drilling exploration for oil or gas, persons, firms, or corporations must obtain a permit from the Division of Land Resources and furnish a surity bond of $5,000 under conditions that any well opened or caused to be opened by an operator shall upon abandonment be plugged in accordance with the prescribed regulations.

A fee of $50.00 must accompany the application which describes and locates the proposed well(s). On-site inspections are made during drilling and after completion of drilling.

Within 30 days after completion of an exploratory well: (a) that well must be plugged according to procedures; (b) a completion report filed; and (c) a complete log of the drilling of the well submitted.

Sets of Plans: One application required.

Process Time: Normally 10 days.

Permit Duration: Duration of activity as conditioned by permit.

Contact:
Division of Land Resources
Post Office Box 27687
Raleigh, NC 27611
(919) 733-4574

APPENDIX D:
DIRECTORY OF OCS-RELATED STATE AND FEDERAL AGENCIES

NORTH CAROLINA STATE GOVERNMENT

Department of Natural Resources and Community Development
P.O. Box 27687
Raleigh, NC 27611 919-733-4984

(This is the address for all DNRCD offices listed, unless otherwise noted.)

DNRCD Regional Offices:

Washington - 1502 North Market Street
Washington, NC 27889 919-946-6481

Wilmington - 7225 Wrightsville Avenue
Wilmington, NC 28403 919-256-4161

Office of Coastal Management, Raleigh 919-733-2293
Director (Ken Stewart)
Assistant Director (David Owens)
*Coastal Energy Impact Program, Coordinator (Jim Smith)

OCM Regional Offices (Coastal Management Field Services)

Elizabeth City - 108 South Water Street
Elizabeth City, NC 27909 919-338-0205

Washington - 1502 North Market Street
Washington, NC 27889 919-946-6481

Morehead City - P.O. Box 769 919-733-2160 or
Morehead City, NC 28557 726-7021

Wilmington - 7225 Wrightsville Avenue
Wilmington, NC 28403 919-256-4161

Division of Environmental Management 919-733-7120

Division of Land Resources (State geologist) 919-733-3833

Office of Regulatory Relations 919-733-6376

---

*Indicates key contact for coastal energy impact matters.

Division of Soil and Water Conservation 919-733-2302

Office of Water Resources 919-733-4064

Division of Marine Fisheries
P.O. Box 769
Morehead City, NC 28557 919-726-7021

Wildlife Resources Commission 919-733-3391

Department of Administration
116 West Jones Street
Raleigh, NC 27611 919-733-7232

Office of Marine Affairs

*OCS Coordinator (Eric Vernon) 919-733-2290

OCS Task Force members (as of June 1981)

Steve Conrad
Division of Land Resources - NRCD
P.O. Box 27687
Raleigh, NC 27611
919-733-3833

Joe Corbin
N.C. State Ports Authority
P.O. Box 3248
Wilmington, NC 28406
919-763-1621

Bill Flournoy
Office of Regulatory Relations - NRCD
P.O. Box 27687
Raleigh, NC 27611
919-733-6376

Derr Leonhardt
Industrial Development Division
Department of Commerce
430 North Salisbury Street
Raleigh, NC 27611
919-733-5146

Chris Mogensen
Energy Division
Department of Commerce
P.O. Box 25249
Raleigh, NC 27611
919-733-5078

Donna Moffitt
Office of Water Resources - NRCD
P.O. Box 27687
Raleigh, NC 27611
919-733-4064

---

*Indicates key contact for coastal energy impact matters.

Ed Regan	Association of County Commissioners P.O. Box 1488 Raleigh, NC 27602 919-832-2893
David Reynolds	N.C. League of Municipalities P.O. Box 3069 Raleigh, NC 27602 919-834-1311
Jim Smith	Office of Coastal Management - NRCD P.O. Box 27687 Raleigh, NC 27611 919-733-2293
Pearson Stewart	Department of Transportation P.O. Box 25201 Raleigh, NC 27611 919-733-2643
Eric Vernon	Office of Marine Affairs 116 West Jones Street Raleigh, NC 27611 919-733-2290
Paul Wilms	Environmental Management Division - NRCD P.O. Box 27687 Raleigh, NC 27611 919-733-5473
Maury Wolff	Division of Marine Fisheries - NRCD P.O. Box 769 Morehead City, NC 28557 919-726-7021

State Property Office 919-733-4346

Department of Human Resources
325 North Salisbury Street
Raleigh, NC 27611 919-733-4534

Environmental Health Section

Solid and Hazardous Waste Management Branch
P.O. Box 2091
Raleigh, NC 27602 919-733-2178

Department of Commerce
430 North Salisbury Street
Raleigh, NC 27611

State Ports Authority
2202 Bernett Boulevard
Wilmington, NC 28406 919-763-1621

UNITED STATES GOVERNMENT

Department of the Interior
18th and C Streets, NW
Washington, DC 20240

Office of Assistant Secretary for Policy, Budget, and Administration

Director, Office of OCS Program Coordinator

Information Officer

Office of Assistant Secretary for Land and Water Resources

Staff Assistant (Leasing)

Office of Assistant Secretary for Energy and Minerals

Staff Assistant (Regulation)

Bureau of Land Management

Director

Energy and Mineral Resources Assistant Director

Division of Offshore Resources, Chief

Branch of Offshore Operations, Chief

Branch of Environmental Assessment, Chief

Branch of Environmental Studies, Chief

Intergovernmental Planning Program, Program Leader

Regional Office: New Orleans OCS Office
Office of the Manager
Hale Boggs Federal Building
500 Camp Street, Suite 841
New Orleans, LA 70130

U.S. Geological Survey

Office of the Director
101 National Center
Reston, VA 22092

Conservation Division, Chief Office
600 National Center
Reston, VA 22092

Regional Office: Conservation Division,
Eastern Region
1725 K Street, Suite 204
Washington, DC 20006

U.S. Fish and Wildlife Service

Ecological Services, Branch of OCS Operations
1375 K Street, NW
Washington, DC 20240

Regional Office: Assistant Regional Activity Leader/OCS
P.O. Box 12559
217 Fort Jackson Road
Charleston, SC 29412

National Park Service

Natural Resources Division, OCS Coordinator
Room 3317
1100 L Street, NW
Washington, DC 20240

Department of Energy

Leasing Policy Development
Room 2317, New Post Office Building
12th and Pennsylvania Avenue, NW
Washington, DC 20461

STATE LIBRARY OF NORTH CAROLINA
3 3091 00748 0452

Federal Energy Regulatory Commission
825 North Capitol Street, NE
Washington, DC 20426

Office of Regulatory Analysis

Office of Producer & Pipeline Regulation

Department of Transportation

U.S. Coast Guard

District Office: Fifth Coast Guard District
Federal Building
431 Crawford Street
Portsmouth, VA 23705

Office of Pipeline Safety Regulation
6226 TransPoint Building
2100 Second Street, SW
Washington, DC 20590

Regional Office: Regional Chief, Eastern Division
Room 5507
2100 Second Street, SW
Washington, DC 20590

Department of Defense

Army Corps of Engineers

District Office: Wilmington District
P.O. Box 1890
Wilmington, NC 28402

Environmental Protection Agency

Office of Environmental Review
401 M Street, SW
Washington, DC 20460

OCS Liaison

Regional Office: Environmental Impact Statements Branch
345 Courtland Street, NE
Atlanta, GA 30308

CEIP Publications

1. Hauser, E. W., P. D. Cribbins, P. D. Tschetter, and R. D. Latta. Coastal Energy Transportation Needs to Support Major Energy Projects in North Carolina's Coastal Zone. CEIP Report #1. September 1981. $10.

2. P. D. Cribbins. A Study of OCS Onshore Support Bases and Coal Export Terminals. CEIP Report #2. September 1981. $10.

3. Tschetter, P. D., M. Fisch, and R. D. Latta. An Assessment of Potential Impacts of Energy-Related Transportation Developments on North Carolina's Coastal Zone. CEIP Report #3. September 1981. $10. (Available spring 1982)

4. Cribbins, P. S. An Analysis of State and Federal Policies Affecting Major Energy Projects in North Carolina's Coastal Zone. CEIP Report #4. September 1981. $10.

5. Brower, David, W. D. McElyea, D. R. Godschalk, and N. D. Lofaro. Outer Continental Shelf Development and the North Carolina Coast: A Guide for Local Planners. CEIP Report #5. August 1981. $10.

6. Rogers, Golden and Halpern, Inc., and Engineers for Energy and the Environment, Inc. Mitigating the Impacts of Energy Facilities; A Local Air Quality Program for the Wilmington, N.C. Area. CEIP Report #6. September 1981. $10.

7. Richardson, C. J. (editor). Pocosin Wetlands: an Integrated Analysis of Coastal Plain Freshwater Bogs in North Carolina. Stroudsburg (Pa): Hutchinson Ross. 364 pp. $25. Available from School of Forestry, Duke University, Durham, N. C. 27709. (This proceedings volume is for a conference partially funded by N. C. CEIP. It replaces the N. C. Peat Sourcebook in this publication list.)

8. McDonald, C. B., and A. M. Ash. Natural Areas Inventory of Tyrrell County, N. C. CEIP Report #8. October 1981. $10 for all requests.

9. Fussell, J., and E. J. Wilson. Natural Areas Inventory of Carteret County, N. C. CEIP Report #9. October 1981. $10 for all requests.

10. Nyfong, T. D. Natural Areas Inventory of Brunswick County, N. C. CEIP Report #10. October 1981. $10 for all requests.

11. Leonard, S. W., and R. J. Davis. Natural Areas Inventory for Pender County, N. C. CEIP Report #11. October 1981. $10 for all requests.

NOTE: Please note renumbering of reports 5-10.

NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION
U.S. DEPARTMENT OF COMMERCE